D.P.U. 96-100

Investigation by the Department of Public Utilities upon its own motion commencing a Notice of Inquiry/Rulemaking, pursuant to 220 C.M.R. §§ 2.00 et seq., establishing the procedures to be followed in electric industry restructuring by electric companies subject to G.L. c. 164.

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EXECUTIVE SUMMARY

Background

This explanatory statement and accompanying proposed rules represent the latest step in a series of initiatives undertaken by the Department of Public Utilities ("Department") aimed at promoting the development of a fully competitive market in the supply of electricity to Massachusetts consumers. This statement follows and amplifies upon our August 16, 1995 Order in Electric Industry Restructuring, D.P.U. 95-30, in which we established our goals for a restructured electric industry. We reaffirm that "[r]educing costs, over time, for all consumers of electricity is the primary objective of the Department's efforts in restructuring the electric industry. The Department's overall goal ... is to develop an efficient industry structure and regulatory framework that minimize costs to consumers while maintaining safe and reliable electric service with minimum impact on the environment." Id. at 13.

In February 1996, in accordance with Electric Industry Restructuring, four electric companies, along with the Commonwealth's Division of Energy Resources, submitted restructuring proposals. None of these represented a negotiated resolution of the issues. The Department opened this rulemaking on March 15, 1996, in response to commenters' requests, in order to address the following issues: (1) market structure, (2) market power, (3) transmission, (4) distribution, (5) stranded cost calculation and recovery mechanism, (6) rate unbundling, (7) performance-based regulation, (8) environmental regulation and demand-side management, (9) default service, (10) universal service, (11) the effect of restructuring on municipal electric companies, and (12) the local and utility tax impacts of restructuring (Order Commencing Notice of Inquiry ("NOI")/Rulemaking and Setting a Procedural Schedule, D.P.U. 96-100, at 5-6 (March 15, 1996)).

The explanatory statement and proposed rules in Attachment A present specific proposals in those areas where the Department believes its future direction is most clear; alternatives in those areas where the Department is less certain of its preferences; and questions on many topics where rules may be warranted but where the Department is not in a position to make any specific proposals. We emphasize that none of these approaches, including those presented as specific proposals, is intended to represent a final resolution of any issue. Rather, they are offered to serve as reference points and to generate response and discussion as this investigation proceeds.

Our vision of a restructured industry includes (1) an independent system operator ("ISO") and a power exchange ("PE") that are independent of those who would transact business with these entities; (2) a regional, zoned network transmission tariff; (3) the functional separation of electric companies into distinct corporate entities with appropriate rules governing interaffiliate transactions; (4) protections to ensure that electricity is available and affordable to all customers; (5) possible mechanisms to provide a reasonable opportunity for stranded cost recovery, options for phased incentives to divest, and a proposal to protect municipalities from loss of electric company property taxes associated with diminished generation plant value; (6) protection of the environment; (7) promotion of energy efficiency and renewable resources; (8) encouragement, but not a requirement, for municipal electric companies to participate in the restructured industry; (9) a price cap system of performance-based regulation; and (10) the unbundling of rates on bills, beginning January 1, 1997, into separate components, i.e., transmission, distribution, and a market proxy for energy costs; and (11) a competitive generation market by January 1, 1998.

Independent System Operator and Power Exchange

An ISO, whose minimum responsibility would be to operate the transmission system in New England in accordance with established reliability standards, represents a first key component of the future market structure. A second key component of the future market structure is a PE, which would facilitate a short-term pool for energy transactions. The Department is committed to ensuring that there is a robust electricity market in the PE, and thus seeks comment on whether electric distribution companies, at least initially, should be required to meet requests from customers for Basic Service with purchases from the PE (see Basic Service, below, and the discussion of alternative approaches to providing Basic Service in the explanatory statement). True independence of the ISO and PE from market participants is an important feature. This framework seems to be consistent with our initial reading of the Federal Energy Regulatory Commission's ("FERC") final rule on transmission access and pricing issued on April 24, 1996 ("FERC Order 888").

Transmission

Also important to the development of a truly competitive market for generation is the implementation of a workable regulatory framework for transmission access and pricing. The Department sees a need for a regional, network tariff that would include adders and subtractors within zones to reflect transmission constraints. The rules established in FERC Order 888 appear to offer promising solutions to issues of jurisdiction, access, pricing, and construction.

Corporate Structure

The Department also includes a proposal for functional separation of electric companies into distinct corporate entities with rules of conduct governing affiliate transactions, which is seen as necessary for full and fair competition in generation markets. The rules of conduct would have distribution companies make service available under non-discriminatory tariffs that offer the same terms to both affiliated and non-affiliated entities in the market, and would provide protections against the potential for abusive interaffiliate transactions. The rules would require electric distribution companies to make customer information (subject to customer approval) available to market participants on the same terms and at the same time that they provide such information to marketing and retail affiliates.

Basic Service and Universal Service -- Consumer Protections

Consistent with its historic consumer protection mandate, under our proposal the distribution company would continue to have an obligation to connect all customers in its service territory to the distribution system and to provide distribution service. As part of a distribution company's obligations, the Department proposes two types of service to ensure that electricity is available and affordable to all customers: Basic Service and Universal Service. The distribution company would be required to provide Basic Service to all customers in its service territory (1) who do not choose to contract directly for electricity with another supplier; (2) who cannot obtain power in the open market; or (3) whose supplier fails, for any reason, to provide electricity. Basic Service would be available to all customers at all times. The Department outlines several options for how the distribution company could buy power to supply Basic Service customers and solicits comment on how to ensure that this service provides competitively-priced power while avoiding possible affiliate abuses. Universal Service, which provides for low-income discounts, will continue to be available to all customers who are currently eligible. The level of the discounts, and the method of collection of the subsidies from other customers will be calculated as they are now. In order to maintain a market price for generation, the discounts will be applied to the regulated components of the bill, i.e., transmission, distribution and stranded costs charges. Universal Service will be available to all eligible customers whether they receive competitive generation service or Basic Service.

The Department's explanatory statement and proposed rules also provide for continued billing and termination protections for Basic Service customers. The relationships between customers and competitive generation suppliers would otherwise be governed by the terms of their contracts. Finally, the Department proposes rules for minimal supplier registration requirements, and requests comment on whether additional rules are necessary to protect customers.

Stranded Cost Recovery and Property Taxes

The proposed rules offer a possible framework for stranded cost recovery. They anticipate that electric companies would be provided a reasonable opportunity to recover the net, nonmitigable stranded costs that were on their books as of August 16, 1995. Before any such recovery can occur, however, each electric company would have to demonstrate that it has taken and will take all reasonable actions to mitigate those stranded costs through sales from generating units, reduction in power purchase contract amounts, asset sales, and other means. The Department seeks comment on options for phased incentives for the sale of generating assets as a means to address both stranded costs and market power concerns. Each company would recover stranded costs through a non-bypassable "stranded cost access charge" that would remain in place across the ten year transition period. Electric companies would have an additional opportunity to recover stranded costs to the extent that they can achieve efficiencies through cost reductions, consistent with the Department's primary objective of reducing costs, over time. Because considerable concern exists regarding the effects of a significant over- or underrecovery of stranded costs, the Department has proposed that, based on actual experience, stranded costs be periodically subject to some degree of reconciliation. Finally, if owners of generating facilities recover their stranded costs, municipalities should expect to receive property taxes commensurate with the sum of the market value and the stranded costs associated with any given facility.

Environmental Protection

Consistent with the principles of Electric Industry Restructuring to support and further the goals of environmental regulation during the transition, the explanatory statement describes the Department's intent to support efforts by the Department of Environmental Protection to ensure that increased competition in electric power supply does not come at the expense of the environment. The Department solicits comments on how to ensure that generators under its jurisdiction take appropriate steps to minimize environmental impacts from restructuring, and on specific options such as setting comparable emissions standards for existing and new generating units, and standards for toxics.

Renewable Energy Resources and Energy Efficiency

During the transition to a restructured industry, Department policies will encourage low environmental impact resources such as renewable energy resources and energy efficiency programs in order to offer these resources a meaningful chance to compete. Regarding renewable energy sources, the Department endorses market-based approaches and outlines three options to promote their development by: (1) encouraging direct purchases from renewable energy resources where renewables might be priced slightly above the market price of electricity; (2) establishing a renewables fund that would be collected through a low, non-bypassable charge; and (3) requiring distribution companies to purchase power generated by customers' on-site renewable energy resources with capacities of 30 kilowatts or less.

The Department remains committed to ensuring that energy efficiency has a meaningful opportunity to compete in the future electric industry for two reasons: to correct market failures and to achieve the public benefits of energy efficiency. Toward that end, the Department expects electric distribution companies to continue their energy efficiency efforts, although we expect demand-side management ("DSM") programs to become increasingly market-driven and to focus on market transformation initiatives.

Municipals

The rules that we propose would apply to the existing investor-owned utilities, and in more limited ways, to certain new entrants to Massachusetts electricity markets. The rules do not change the jurisdictional boundaries of the Department with respect to municipal electric companies, nor do they seek to require the involvement of municipal electric companies in the restructuring process. We do encourage municipal electric companies to integrate their activities with those of the restructured industry for the benefit of all consumers in the Commonwealth.

Performance-based Regulation

In accordance with its principle favoring incentive forms of regulation, the Department establishes its preference for price cap regulation for all electric distribution companies. Bills from electric distribution companies would include a component for services provided by a distribution company that would be governed by a price cap formula. The price cap formula would adjust a price cap index by factors to accommodate inflation, changes in productivity, and exogenous costs. These price caps would be adjusted annually and would remain in place for five years. The other components of bills from electric distribution companies might include a pass-through of market generation charges, a pass-through of FERC-approved transmission charges, a stranded cost access charge, and a general access charge to support low-income discounts, energy efficiency programs, and the renewables fund.

Implementation of Unbundled Rates Beginning January 1, 1997

As we pursue steady progress toward a restructured electric industry in Massachusetts, we plan to begin implementing revenue-neutral, unbundled rates in early 1997 in keeping with the schedule established in our March 15, 1996 Order in this proceeding. Through the rate unbundling process, we anticipate that customers will become familiar with an unbundled bill format, the different components of the cost of electricity, and movements in the cost of electricity in a competitive generation market through market proxy pricing.

A Competitive Generation Market by January 1, 1998

By promulgating regulations that support a competitive generation market in those areas over which we have jurisdiction, and providing guidance or making policy recommendations on those issues where we do not have jurisdiction, or where it may be shared, we hope to eliminate any barriers to a fully competitive generation sector within the Commonwealth of Massachusetts by January 1, 1998, and to lend impetus to the structural changes required at the federal and regional level at the same time.

Conclusion

We intend to work cooperatively with the Massachusetts Legislature, with our fellow New England regulators, and with other state and federal authorities to accomplish the goal of an efficient industry structure and regulatory framework. The Department appreciates the efforts of all who have contributed proposals and comments to date in this proceeding. We look forward to continued participation by commenters in the upcoming hearing and comment stages of this proceeding as we endeavor to restructure the electric industry in a way that will best serve consumers in the Commonwealth. Further, we hope that the additional clarity provided by this explanatory statement and the proposed rules will encourage further negotiations among Massachusetts electric companies and other stakeholders and result in settlements of the outstanding company-specific electric restructuring dockets.

I. HISTORY OF THE PROCEEDING

On August 16, 1995, the Department of Public Utilities ("Department") issued its Order in Electric Industry Restructuring, D.P.U. 95-30, setting forth principles for a restructured electric industry and for the transition to the future, establishing a schedule for electric companies to file restructuring proposals, and encouraging utilities to present negotiated settlements. On February 13, 1996, the Division of Energy Resources ("DOER") filed its plan for restructuring the electric industry. On February 16, 1996, the Department received restructuring plans from four companies: Boston Edison Company, Eastern Edison Company, Massachusetts Electric Company, and Western Massachusetts Electric Company. The four utility proposals were docketed respectively as D.P.U. 96-23, D.P.U. 96-24, D.P.U. 96-25, and D.P.U. 96-26. None of the plans represent a negotiated resolution of the issues.

On March 4, 1996, the Department issued a draft proposed schedule and, on March 6, 1996, held a consolidated procedural conference to receive comment on the proposed schedule.[1] After an additional period for written comments,[2] the Department, on March 15, 1996, issued an Order commencing a Notice of Inquiry ("NOI")/Rulemaking, setting a procedural schedule and docketing this case as D.P.U 96-100. The scope of the NOI/Rulemaking includes issues pertaining to (1) market structure, (2) market power, (3) transmission, (4) distribution, (5) stranded cost calculation and recovery mechanism,

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[1] On February 16, 1996, the Department issued Orders of Notice in each of the company cases, requiring each company that filed a restructuring plan to publish notice of the procedural conference as well as notice of a public hearing in newspapers of general circulation in its service territory, and requiring each company to provide this notice to the service list in D.P.U. 95-30.

[2] Written comments were received by the deadline of March 7, 1996, from the Attorney General; Barnstable County Commission; Boston Edison Company; COM/Electric; Competitive Power Coalition of New England, Inc.; Conservation Law Foundation; Division of Energy Resources; Enron Capital and Trade Resources; Fitchburg Gas and Electric Light Company; General Electric et al; Massachusetts Municipal Wholesale Electric Company; Thomas C. Norton, Senate Majority Leader; Retailers Association of Massachusetts; the Town of Lexington; and Western Massachusetts Electric Company.

(6) rate unbundling, (7) performance-based regulation, (8) environmental regulation and demand-side management, (9) default service, (10) universal service, (11) the effect of restructuring on municipal electric companies, and (12) the local and utility tax impacts of restructuring (Order Commencing Notice of Inquiry ("NOI")/Rulemaking and Setting a Procedural Schedule, D.P.U. 96-100, at 5-6 (March 15, 1996)). Among other things, the Department's March 15, 1996 procedural schedule provided that interested persons could file comments on or before April 12, 1996, limited to twenty pages, analyzing and proposing changes to the five restructuring plans filed with the Department in February, 1996. The Department received a number of filed comments.[3] This explanatory statement reflects, to a limited degree, the comments that were received on or before April 12, in keeping with the Department's March 15, 1996 procedural schedule. While we have attempted to give careful

[3] On or about April 12, 1996, the Department received comments from Alternate Power Source, Inc.; American National Power; Anglo Fabrics Company, Inc.; Associated Industries of Massachusetts; Association of Independent Colleges and Universities in Massachusetts; the Attorney General; Boston Edison Company; Brandeis University; Brodie Mountain Ski Resort; Building Owners and Managers Association; Center for Energy and Economic Development; Citizens Lehman Power L.P.; COM/Electric; Competitive Power Coalition of New England; Consumers for Affordable Clean Electricity; Crystal Systems; David Clark Company, Inc.; Division of Energy Resources; DuPont Merck; Eastern Edison Company; Enron Capital & Trade Resources; Fitchburg Gas and Electric Light Company; The Flatley Company; Freedom Energy Company, L.L.C.; Guaranty Management Company, Inc.; Heyes Forest Products; INCOM; Kelly Molded Products; Kopin Corporation; The Low Income Consumers by the National Consumer Law Center, Inc.; Lynn Area Chamber of Commerce; Malden Redevelopment Authority; Massachusetts Energy Efficiency Council; Massachusetts Municipal Light Plants; Massachusetts Municipal Wholesale Electric Company; Massachusetts Electric Company; Merrimack Valley Chamber of Commerce; New England Plating Co, Inc.; Park Avenue Market; Prolerized New England Co.; Quincy Youth Arena, Inc.; Renewable Energy Technology Analysis; Retailers Association of Massachusetts; Thomas C. Norton, Senate Majority Leader; Town of Lexington; Tufts University; Union of Concerned Scientists; Western Massachusetts Electric Company; and Western Massachusetts Electric Company Industrial Customer Group.

consideration to all that was presented, the volume of comments received and magnitude of issues raised dictate that we defer a more careful review of these comments to hearings and subsequent deliberations in this proceeding.

The procedural schedule established by the Department in its March 15 Order also provided that the Department issue proposed rules to govern the restructuring process in Massachusetts, with an accompanying explanatory statement, on May 1, 1996. The Department's decision to issue the May 1 explanatory statement and proposed rules was motivated in large part by the many comments that were received during the March 6 procedural conference and in subsequent written comments to the Department. These comments requested a statement by the Department providing further guidance on the resolution of key, generic issues, and suggested that such a statement would be necessary to provide additional incentives for settlement, to advance the restructuring process, and to maximize the efficiency of proceedings addressing generic issues.[4] This Order responds to that request. The Department's objective in this Order is to provide a vision of a viable framework for restructuring the electric industry in Massachusetts, within the context of the goals and principles established in D.P.U. 95-30.

The explanatory statement and proposed rules in Attachment A offer guidance by presenting the Department's specific proposals, ideas on options, and questions regarding the resolution of key, generic issues in industry restructuring. We emphasize that the approaches that are identified as proposals by no means represent a final resolution of any issue. Rather, they represent a set of approaches that seem most solidly founded in economic and regulatory theory, given the discussions that have taken place in Massachusetts and across the country in

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[4] Those who requested that the Department issue a statement include the Attorney General; Boston Edison Company; COM/Electric; Conservation Law Foundation; Competitive Power Coalition of New England, Inc.; General Electric et al; and Western Massachusetts Electric Company.

the last two years. The views we express here are preliminary and are subject to change as we proceed with the investigation.

Our vision of a restructured industry includes: (1) an independent system operator ("ISO") and a Power Exchange ("PE") that are independent of those who would transact business with these entities; (2) a regional, zoned network transmission tariff; (3) functional separation of electric companies into distinct corporate entities with appropriate rules governing interaffiliate transactions; (4) no requirement to divest, but options for phased incentives to divest to promote a more robust competitive market; (5) protections to ensure that electricity is available and affordable to all customers; (6) assurance of a reasonable opportunity for stranded cost recovery; (7) promotion of environmental goals and renewable energy resources; (8) energy efficiency; and (9) a price cap system of performance-based regulation. We distinguish our specific proposals for a restructured industry from a number of options that have appeal but that warrant additional exploration in this inquiry. Finally, in several areas where the very limited nature of the information available to us precludes us from developing even initial impressions of what might be workable approaches, the Department raises a number of questions for commenters. These questions are presented at the end of each section.

The Department recognizes that it does not have jurisdiction over all elements of restructuring. Consistent with our March 15, 1996 procedural ruling, we have proposed rules in those areas where we have jurisdiction. Where we do not have jurisdiction, or where it may be shared, we have outlined options, or raised questions for consideration. Given that the Massachusetts electric utility companies are members of the New England Power Pool ("NEPOOL"), and three of the electric utility companies in Massachusetts are subsidiaries of multi-state holding companies,[5] and because of federal and state interests, it is critical that

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[5] Eastern Edison Company is a subsidiary of Eastern Utilities Associates; Massachusetts Electric Company is a subsidiary of New England Electric System; and Western (continued...)

there be coordination between Massachusetts and other state jurisdictions in the restructuring of the electric industry. The Department is committed to working with federal and state authorities and our fellow New England regulators to accomplish the goal of a restructured electric industry.

The Department notes that on April 25, 1996, the Federal Energy Regulatory Commission ("FERC") issued a final rule related to open access transmission and stranded costs. Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities 75 FERC ¶ 61,080 ("FERC Order 888"). The rules comprehensively address a wide range of electric industry restructuring topics related to transmission access and pricing, electricity system market structure, federal/state jurisdiction, wholesale and retail access, and stranded cost recovery. Given the complexity of the issues and the length of FERC's ruling, the Department has not attempted to reflect FERC Order 888 fully in this explanatory statement or draft rules. However, our initial review indicates broad areas of agreement between the Department's proposals and FERC's final rule. Moreover, the Department believes that it will be critical to ensure that the ultimate policies and rules that the Department adopts give full consideration to FERC Order 888. We invite parties to provide comment on the impact of FERC's decision on the policies we set forth in this statement.

In addition, we note that certain statutory changes will be necessary in Massachusetts to accomplish our goals in restructuring and we are committed to working with the stakeholders and the Legislature to develop necessary legislation.[6] We will continue to keep the Legislature apprised of our policy proposals and our progress as we proceed. We solicit comments

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(…continued)
Massachusetts Electric Company is a subsidiary of Northeast Utilities.

[6] The Department considers that our proposals regarding the future restructured industry are generally consistent with the recommendations contained in the report of the Senate Committee on Post-Audit and Oversight on restructuring, A Prescription for Competition: The Electric Utility Industry (S.2130) November 30, 1995.

regarding the Department's jurisdiction over issues raised in this explanatory statement and the extent to which state or federal legislation is required to implement any of our proposals.

By creating regulations covering those areas over which we have jurisdiction, and providing guidance on other issues, we are working to eliminate any barriers to a fully competitive generation sector within the Commonwealth of Massachusetts and to lend impetus to the structural changes required at the federal and regional level for restructuring. Further, we hope that the additional clarity provided by this explanatory statement and the proposed rules will encourage further negotiations among Massachusetts utilities and other stakeholders and assist in settlements of the outstanding company-specific electric restructuring dockets.[7]

II. GOAL FOR RESTRUCTURING

In D.P.U. 95-30, at 13, the Department announced its goal for a restructured electric industry. "Reducing costs, over time, for all consumers of electricity is the primary objective of the Department's efforts in restructuring the electric industry. The Department's overall goal . . . is to develop an efficient industry structure and regulatory framework that minimize costs to consumers while maintaining safe and reliable electric service with minimum impact on the environment." Id. The Department stated that long-term cost reductions would most effectively be achieved by allowing customer choice and full and fair competition in the generation of electricity. Id. at ii. The Department further found that the interests of ratepayers would best be served by an expedient and orderly transition from regulation to competition in the generation sector. Id. These remain the Department's goals.

In D.P.U 95-30, the Department also developed principles that describe the key characteristics of a restructured electric industry. These principles are: (1) provide the

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7 The four outstanding electric restructuring dockets are Eastern Edison Company (D.P.U. 96-23), Boston Edison Company (D.P.U. 96-24), Massachusetts Electric Company (D.P.U. 96-25), and Western Massachusetts Electric Company (D.P.U. 96-26). Pursuant to our procedural schedule issued on March 15, 1996, the company-specific adjudications are scheduled to begin after the final regulations in D.P.U. 96-100 become effective.

broadest possible customer choice; (2) provide all customers with an opportunity to share in the benefits of increased competition; (3) ensure full and fair competition in generation markets; (4) functionally separate generation, transmission, and distribution services; (5) provide universal service; (6) support and further the goals of environmental regulation; and (7) rely on incentive regulation where a fully competitive market cannot exist, or does not yet exist.

The Department also set out principles for guiding the transition from a regulated to a competitive industry structure which identify fundamental conditions for facilitating the transition process and ensuring that the end result benefits customers. The transition period is the period between the effective dates of the final rules and the realization of a fully competitive generation market with full retail choice. The transition principles are: (1) honor existing commitments; (2) unbundle rates; (3) seek near-term rate relief; (4) maintain demand-side management programs; and (5) ensure that the transition is orderly and expeditious, and minimizes customer confusion. This statement and the attached draft rules reflect our continuing support for these principles.

III. THE COMING ELECTRICITY MARKET

A. Overview

In this Order, the Department communicates its view of the framework for a future market structure that we believe will best achieve the goal of lowering costs to customers through reliance on competitive forces, and that is consistent with the principles for restructuring that we established in D.P.U. 95-30. The Department anticipates a restructured electric industry in which all customers would have the option to purchase generation services from a wide range of providers operating in a competitive market. Transactions between buyers and sellers would occur through a variety of mechanisms (e.g., bilateral transactions, spot market) established by the market participants, with suppliers competing for customers on the basis of a variety of factors including, but not necessarily limited to, price, contract duration, payment terms, type of generation, and type of electric service. Owners of transmission assets would transfer control over these assets, through lease or other arrangements, to an ISO that would provide open, non-discriminatory access to all users of the transmission grid. Finally, electric companies would provide distribution services on a non-discriminatory basis to all customers in their service territories. Thus, generation would be provided on a competitive basis, and transmission and distribution would remain monopoly functions, subject to federal or state regulation, respectively.

The Department recognizes that the federal government has jurisdiction over most of the questions that relate to the structure of the market, and that cooperation with other New England states will be required to implement the changes we envision. Nevertheless, in the interests of ratepayers in Massachusetts and in the region, the Department is committed to moving forward and we intend to remove all obstacles to the future we envision that are within our jurisdiction by January 1, 1998. In addition, we will pursue our objective of lowering electricity costs through greater competition in cooperation with the Massachusetts legislature, our neighboring states, and federal authorities.

In developing our view of the future, the Department must keep in clear focus both the benefits of the current industry structure, and the regional market for the generation and delivery of electricity in Massachusetts. For over two decades, NEPOOL's coordinated operation of the bulk power system in New England has provided electric companies and their customers with critical and significant benefits in terms of power supply reliability and cost savings.[8] It is important that these benefits not be lost in the transition to a new market structure.

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8 Currently, the generation and transmission facilities of Massachusetts electric companies are dispatched and operated as if they were a single New England-wide company in accordance with the provisions and protocols contained in the NEPOOL Agreement, and related NEPOOL Criteria, Rules and Standards. Generation facilities of the NEPOOL members are dispatched based on their fuel expense, and savings that result from coordinated generation dispatch are shared among NEPOOL members.

The NEPOOL Executive Committee ("NEC") is contemplating changes in NEPOOL to adapt its organizational and operational structure to the evolving competitive conditions in the electric industry.[9] Under the changes being considered by NEPOOL, the New England Power Exchange, the operating arm of NEPOOL, would continue its role as the system operator responsible for the scheduling and dispatch of the New England bulk power system in accordance with Northeast Power Coordinating Council ("NPCC") and North American Electric Reliability Council ("NERC") reliability standards and protocols. In addition, NEPOOL's contemplated changes include moving to bid pricing for dispatch and automatic generation control ("AGC"), expanding membership and the representation of market participants, unbundling market products, and reducing time for the calculation of capacity requirements in order to track more closely the transactions of a dynamic market.

The Department commends the members of NEPOOL for considering implementing changes to the NEPOOL Agreement that would maintain the reliability benefits of NEPOOL, while converting to a system under which all generating units would be subject to the competitive pressures of the marketplace. The changes that are being contemplated by NEPOOL represent important steps towards the development of a fully competitive generation market in New England. The Department urges NEPOOL to move forward with its process and to file amendments with FERC that comply with FERC Order 888 as soon as practical.

Beyond the changes contemplated by NEPOOL, the Department is mindful of our ultimate goal for the electricity consumers of the Commonwealth -- that is, the lower costs to consumers for electricity services that will result from a competitive market for generation. A deregulated generation sector that relies upon competitive pressures instead of traditional cost-based regulation will produce superior results for consumers only if certain features are

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[9] The NEC has formed the NEPOOL Review Committee ("NRC") for the purpose of undertaking a review of NEPOOL's structure in light of changes occurring in the industry. The Department's understanding of changes being contemplated by NEPOOL derive from the NEPOOL Plus document introduced in the NRC effort, as well as the NRC's refinements of the concepts therein.

present. For the full benefits of a competitive generation market to be available to consumers, the prerequisites for a truly competitive market must be in place. Such a market must meet certain standards -- for example, there must be (1) many buyers and sellers with effective access to each other, (2) arms-length transactions between buyers and sellers, (3) broad and equal access to timely market information, and (4) low thresholds for entry. Most important, it is critical that no market participant, or group of participants, can exercise unfair or abusive market power in a new competitive industry structure. The Department thinks that the changes being considered are not sufficient in and of themselves to achieve the Department's goal of full and fair competition in the generation market. They do not adequately address the four elements listed above, and consequently, the potential for abuse of market power in transmission and/or generation in the restructured market of the future.

Minimizing this potential can be achieved through many strategies. The Department favors strategies that rely on the structure of the market and on incentives to the greatest extent possible rather than on regulatory policing and after-the-fact remedies. The Department's intention is to create a fair and fully competitive market. We recognize that there will be stronger and weaker competitors, and that all may not thrive in the market. In developing our vision of the restructured industry, the Department seeks to foster the benefits of competition itself rather than to protect individual competitors.

We outline the components of a market structure that we think may be necessary for the development of a truly competitive market for generation. This structure would require changes beyond those currently being contemplated by NEPOOL. The structure is characterized by a bulk power system operator ("ISO"), that is truly independent of participants in the market. The Department thinks that an ISO must be responsible, at a minimum, for those activities necessary to ensure that NPCC and NERC reliability standards will continue to be met. The Department assumes that this ISO would continue to operate the entire New England bulk power system as a single control area. We also envision the existence of a separate entity to clear short-term energy transactions ("Power Exchange" or "PE"). The Department believes that both an ISO and a PE could evolve separately out of NEPOOL. Their development does not require abandoning the foundation of the regional bulk power system.

In the following sections, the Department proposes in more detail its initial views of the components of a restructured industry.

B. The Independent System Operator

The Department uses the term "Independent System Operator" or "ISO" to refer to the entity whose responsibility, at a minimum, will be to operate the transmission system in New England in accordance with NERC/NPCC reliability standards. The Department notes that the term ISO has been used differently by different commenters, and we do not intend to endorse any particular representation that has been used to date. The Department intends to further refine its definition of the ISO after consideration of FERC's principles on ISOs, and comments received in this proceeding.

Below, the Department outlines the role and responsibilities of an ISO, as we see them, which would be effective in achieving our goals for a restructured industry. A key question is how to ensure that the structure of an ISO, and its relationship to market participants, will prevent the undue exercise of market power (as derived from either transmission or generation assets) by market participants. As noted above, the Department is concerned that the proposed changes to NEPOOL, which continue to require a system of member voting and governance applied to the bulk power system operator, may not accomplish this overriding objective.

We are certain that it will be necessary for an ISO to obtain control over transmission facilities from the owners of these facilities, through lease or other arrangements. Further, the Department thinks that an ISO should fulfill its responsibilities pursuant to performance-based regulation incentives. However, the Department is interested in determining if resolution of market power issues in New England requires establishment of an ISO that has no corporate relationship to any market participant, and if not, how membership and governance rules can be established so that no owner can control the operations of the ISO and so that no group of participants can exert excessive influence. The Department invites interested parties to provide comment on this matter. The Department notes that FERC has outlined principles for an ISO in its final rule. The Department solicits comments on FERC's principles. Finally, while FERC would regulate an ISO, the Department expects the public utility commissions in New England will provide meaningful and coordinated input into this oversight function.

1. Minimum Responsibilities of an ISO

An ISO must operate the New England bulk power system according to NERC/NPCC reliability standards. The Department's initial view is that exclusive ISO control over the dispatch of all generating facilities would not be necessary to achieve reliability standards. However, we anticipate that an ISO would have to establish at least the following:

* Procedures that govern the submission of unit dispatch schedules arranged through market participant contracts and/or through the PE, and procedures that will be followed by the ISO to dispatch units in consideration of such schedules;
* Procedures that govern the ISO's actions with respect to unit dispatch in the event that maintaining system reliability requires deviations from the dispatch schedules presented by generation suppliers;
* Procedures by which all requests to take a transmission line out of service for maintenance are reviewed and approved by the ISO;
* A means to secure AGC for at least some generating units;
* A means to secure operating reserves at all times; and
* A means to secure any ancillary services necessary to maintain system reliability.

Over time, within the guidelines outlined above, an ISO should be able to rely on competitive markets and financial incentives and penalties to obtain many of the services necessary to ensure system reliability. For example:

* Rules that govern the submittal of energy dispatch schedules should require only the minimum notice necessary for reliable operation, in consideration of the structure of the bulk power system, and in consideration of the resources of the ISO;
* Rules that govern market participant obligations with respect to capacity, reserves, and ancillary services should rely on financial incentives and competitive markets whenever doing so does not interfere with the ability of the ISO to maintain system reliability; and
* Rules that govern ISO procurement of AGC, reserves, and ancillary services should provide that such procurement rely upon competitive markets whenever possible.

The Department invites comment regarding the minimum level of responsibility necessary for an ISO in New England to maintain power system reliability. Critical to this determination is the technical configuration of the bulk power system, and the resource limitations of the system operator. The Department requests comments on these issues and on the following questions:

1. To what extent would the configuration of generation and transmission resources in the New England region limit an ISO's ability to rely solely on the nominated dispatch schedules of market participants (consistent with bilateral transactions) and the PE for the purpose of generating unit dispatch? (For a discussion of the role of the PE, see Section III.D., below.)

2. In consideration of the technical resources of an ISO, what are the minimum notice requirements for bilateral transactions necessary to allow for reliable scheduling of generating facility dispatch?

3. One possible approach would be to allow an ISO broad control over dispatch, at least initially, and to phase down the extent of ISO dispatch control over time as the new market structure takes hold and market participants and operators of distribution systems gain experience with the new structure. Please discuss the

operational and competitive benefits and drawbacks of such an approach. If such an approach is feasible, please discuss possible timing and other criteria for its implementation.

2. Additional Responsibilities of an ISO

The Department questions whether an ISO should have responsibilities beyond the minimum necessary to ensure reliability, but we intend to consider such matters fully throughout this investigation. We invite comment on this matter, and on the questions that follow:

1. Should there be an expanded role for an ISO during the transition period in order to facilitate the development of a competitive generation market? How would the ISO, in its expanded role, facilitate such development?

2. Should an ISO have control over the dispatch of all generating units for reasons of economic efficiency? Can the benefits of such control be demonstrated based upon the operating history of NEPOOL and what we understand to be the increase in the number of bilateral arrangements between utilities and consequent decrease in size of the NEPOOL savings pool?

3. Would expanded ISO control over the dispatch of generating units avoid the development of what could be a two-tiered market, whereby the most desirable units would be captured by bilateral contracts and the remaining units are available to the PE? If so, how?

4. Should an ISO have control over the dispatch of all generating units in order to facilitate transmission congestion pricing in the region? How would ISO control facilitate this?

5. Should the role of an ISO be expanded to include the monitoring of generation portfolio emissions to ensure continued progress in compliance with federal environmental initiatives? How would the ISO provide this information, or make this information available in a format useful for relevant environmental agencies?

C. Transmission

Transmission plays an essential and complex role in the electric industry. Transmission is essential because it contributes to the reliability and stability of the electric system. It also provides a vital link between customers and a wide range of suppliers. Transmission is complex in that fluctuating levels of local and regional use must be continuously balanced across time and location while remaining within system capabilities and industry standards.

The Department addresses below the issues of transmission jurisdiction, pricing, and construction.

1. Jurisdiction

The Department notes the importance of a clear and workable jurisdictional arrangement over transmission and distribution in the coming electricity market. Introducing multiple jurisdictional requirements or adding layers of regulation over transmission would seem to offer little by way of benefits to ratepayers. In the Department's view, the regulatory responsibility for transmission in interstate commerce appropriately resides with FERC. Our view appears to be consistent with the jurisdictional assertions provided by FERC in its Order 888.[10] The Department believes that FERC's jurisdictional arrangement is workable and that it promises to substantially reduce or even eliminate uncertainty. In the near term, in the spirit of cooperative federalism, the Department intends to work with FERC to resolve jurisdictional issues that may remain regarding transmission and distribution. In the longer term, federal legislation more clearly delineating the division between transmission and distribution might be beneficial. The Department intends to work with FERC and the Congress to achieve a workable distinction between the jurisdictional spheres or to develop a workable system of joint jurisdiction where necessary.

The Department will continue to exercise regulatory oversight over distribution services. The precise dividing line between transmission and distribution is not clear.[11]

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[10] In FERC Order 888, FERC stated that it has jurisdiction over wholesale transmission in interstate commerce and unbundled retail transmission in interstate commerce. FERC Order 888, at 400-442; Appendix G. FERC stated that it generally expects unbundled retail wheeling customers to take service under the same FERC tariff that applies to wholesale customers, but that departure from this general expectation may be provided to meet state concerns. Id. at 440.

[11] In FERC Order 888, at 400-442, FERC adopted seven indicators of local distribution, to be evaluated on a case-by-case basis: (1) local distribution facilities are normally in close proximity to retail customers, (2) local distribution facilities are primarily radial in character, (3) power flows into local distribution systems; it rarely, if ever, flows out, (4) when power enters a local distribution system, it is not reconsigned or transported to some other market, (5) power entering a local distribution system is

Consistent with our preliminary understanding of Order 888, the Department believes FERC's demarcation between transmission and distribution should and in fact will allow for every retail electricity transaction in Massachusetts to include a component that is jurisdictional to the Department so that our policy requirements in restructuring will not be bypassable. The Department requests comment on whether a customer may be able to bypass our policy requirements in restructuring and under what circumstances. In general, a plausible demarcation between transmission and distribution may be the difference in voltage level, i.e., facilities at or above 69 kilovolts ("KV") could be identified as transmission under federal jurisdiction, while facilities below that level could be identified as distribution under state jurisdiction.[12] This demarcation is reflective of California's approach, where facilities assigned to the ISO would be identified as transmission under federal jurisdiction while facilities downstream of the ISO would be identified as distribution under state jurisdiction. The Department believes that additional clarity on this issue will be provided by application of the method adopted by FERC, although, as noted earlier, a final resolution of jurisdictional issues may require federal legislation.

2. Pricing

Pricing parity, or like pricing for like services, is the goal of transmission comparability. To allow any customer group to enjoy an arbitrary advantage not accorded to others is by definition unduly discriminatory and preferential. Moreover, true competition within the generation sector will be distorted to the extent that transmission pricing is provided on a dissimilar basis. To achieve comparability in a competitive industry, the Department

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consumed in a comparatively restricted geographical area, (7) meters are based at the transmission/local distribution interface to measure flows into the local distribution system, and (7) local distribution systems will be of reduced voltage.

12 Facilities of 69 KV and above provide most of the bulk power transmission in New England. This line of demarcation may not be applicable throughout the entire region, however, and applications of the method adopted by FERC in Order 888 and legislative proposals may allow for flexibility to include lower-voltage facilities where exceptions are demonstrably necessary.

expects that distinctions between native load[13] and third-party customers would be eliminated with respect to transmission pricing, terms, and conditions. This expectation is particularly relevant to the Department's plan to implement direct access on January 1, 1998.

Transmission pricing should include incentives for efficient use of the transmission system. A regional network tariff, including zoned rates with adders and subtractors to reflect constraints, could provide important information to transmission owners and users, as well as generation developers, leading to a more efficient use of existing transmission facilities and development of new transmission facilities over time. Such pricing would also reflect the regional nature of the power market in New England. In particular, a regional network tariff appears to fully conform with existing NEPOOL practices. Transmission planning, grid operation, economic dispatch, and intra-pool coordination are all conducted by NEPOOL on behalf of the region. Over the past several decades, NEPOOL's willingness to promote and implement regional approaches has contributed measurable benefits to New England customers. Moreover, a regional network tariff would alleviate competitive distortions caused by multiple tariffs assigned to transactions crossing multiple systems, otherwise known as "pancaking." Essentially, pancaking overcollects transmission costs relative to costs that would be incurred if transmission systems were to operate on an integrated basis.

The Department's view is that sunsetting existing preferential transmission pricing arrangements which tend to favor existing power pool members while discriminating against non-members is also desirable. Our initial understanding of Order 888 is that FERC has also recognized the anticompetitive nature of preferential transmission pricing arrangements within power pools, and that remedies will be required. Generally, the Department intends to support termination of preferential transmission pricing arrangements upon sale of an entitlement by the original holder. However, if termination of a preferential transmission arrangement upon

[13] Native load is the retail customer component of a vertically integrated utility's services. Essentially, the residential, commercial, and industrial customers within an electric utility's service territory constitute the native load of that electric utility.

sale is likely to create a barrier to divestiture of generating units, the Department may consider supporting a transfer of preferential transmission pricing to the new owner as a means of encouraging divestiture. Such divestiture would tend to alleviate market power concerns while fostering development of a robust market with many sellers.

3. Construction

Transmission constraints can hinder suppliers' access to markets and effectively foreclose transactions that would otherwise be economically desirable. In addition, constraints can impede reliable operation of the grid. While not every constraint should be assumed to be a critical constraint, the Department notes the desirability of establishing mechanisms to deal with constraints. To that end, the Department has a strong preference for market-based mechanisms over administrative ones to determine and support necessary construction. Market-based mechanisms could include price signals indicating when and where transmission is constrained, advance contracts for congestion as a method of allocating transmission capacity, and a secondary market for transmission capacity. Incentive mechanisms, administered by the ISO, could provide a strong impetus for necessary transmission enlargement.

D. The Power Exchange

The Department uses the term "Power Exchange" or "PE" to describe an entity whose responsibilities include facilitation of a short-term pool for energy market transactions, at least for a transitional period, and possibly on a permanent basis as part of the future market structure.

The Department believes that the key issue related to the PE is its relationship, over time, with the ISO and with market participants. The Department's initial view is that the PE should not have any corporate relationship with market participants, and we do not see compelling reasons why the merchant function of the PE should be combined with the reliability function of the ISO. To the contrary, the Department thinks that complete separation of the two can avoid problems that may arise related to market power and affiliate transactions, and may avoid disputes over dispatch order decisions of the ISO.

The Department is concerned that permitting electric companies that own generation and transmission or distribution to sell electricity from their own generating units to their own customers (e.g., in a standard offer) might slow the development of a robust market for generation. Our concern is that initially the market will not be sufficiently robust to generate clear and transparent spot market prices in the PE. One approach to address this concern would be to require initially that electric companies that own generation and transmission or distribution sell all of their generation into the PE and purchase power on behalf of their customers from the PE. Once a robust generation market is established, companies retaining generation and distribution affiliates could purchase power on behalf of their customers from non-affiliated sources of generation. The benefits of such an approach would be to (1) dramatically reduce the scope and regulatory burden of issues related to market power, (2) ensure that customers share equally in the benefits of competitive market prices, and (3) provide sufficient depth to the PE that its market signals provide a benchmark for contracts for differences or direct access arrangements.

A second approach would allow an electric company to provide a standard offer (based on its own generating assets) to its customers while adopting safeguards that would protect against potential market power abuse or other diminution of robust competition in the generation market. The benefits of the second approach would be to (1) allow continuity in electric companies' service of their customers, (2) enable electric company customers to benefit from low-cost generating units of their current electric company, and (3) provide another choice for customers.

The Department invites comment on the function and structure of the PE, and on the questions that follow:

1. Would requiring the distribution company to purchase from but not requiring the generation company to sell into the PE be sufficient to support a robust PE?

2. What safeguards would be necessary to allow an electric company to provide a standard offer (based on its own generating assets) to its customers while protecting against potential market power abuse or other diminution of robust competition in the generation market? Would allowing other providers the opportunity to match the standard offer and allocating the customers among them and the electric company be an adequate safeguard?

3. It has been asserted that the merchant function of the PE must be integral to the operational decisions of the ISO in order to produce an economically efficient dispatch and to identify appropriate pricing of transmission congestion. Is this true or necessary in the New England region? Can this be demonstrated based on the operational experience of NEPOOL and what we understand to be the increase in the number of bilateral arrangements between utilities and the consequent decrease in the size of the NEPOOL savings pool?

4. In consideration of the potential abuse of vertical market power, should there be requirements that all electric companies that do not divest themselves of generation conduct affiliate transactions through the PE? In the absence of such a requirement, what alternative mechanisms are sufficient to protect consumers and suppliers not affiliated with electric companies against such potential abuse?

5. Should the rules that govern presentation of the PE's dispatch schedule to the ISO be any different than the rules that govern the presentation of dispatch schedules by any other market participant? If so, why?

E. Corporate Structure

As discussed above, the current system is one in which vertically integrated electric companies participate in a bulk power system run by NEPOOL. In a more competitive industry, where generators are competing for customers, the potential exists for vertically integrated electric companies, which own generation, transmission, and distribution, to favor their affiliates. Modifying the structure and rules of the bulk power system, while maintaining existing corporate structures, may not be sufficient to curtail the potential for abuse of market power and associated decreases in the economic efficiency of competition without a burdensome and costly level of regulatory oversight. A restructuring of the industry that does not limit the potential for market power abuses could lead to anticompetitive pricing at levels higher than those that would prevail under cost-based regulation. Such an outcome would defeat the very purpose of the Department's initiative to deregulate the supply sector and is thus unacceptable. Therefore, the Department believes it is necessary that electric companies modify their corporate structure in order for regulation of the supply function to be lifted.

The options for modifying corporate structure range from creating separate functional divisions within a corporation to corporate divestiture. The level of regulatory supervision necessary to avert market power abuses is likely to be correlated largely with the degree of corporate separation. The separation of functions within a corporation, whether by creating separate divisions or "firewalls" that limit communications within a corporate entity, may not be sufficient to avoid abuses, and could require excessive time and regulatory intervention to detect abuses of market power. In D.P.U. 95-30, at 16, the Department stated that "the functional separation of generation from transmission and distribution services is a necessary first step to address market power issues and limit a company's ability to provide itself an undue advantage in buying or selling services in competitive markets." The Department continues to believe that functional separation is the minimum acceptable approach, and defines the concept further here as the creation of separate corporate entities (e.g., generation, transmission, marketing, and distribution subsidiaries) under one holding company. The Department requests comments on the feasibility, effectiveness in mitigating market power, and consequences of such corporate restructuring.

Although the Department identifies a specific minimum acceptable approach, some electric companies may wish to take additional steps to separate the generation function from the transmission and distribution functions of the company. The Department encourages each electric company to propose a structure that is suitable to its circumstances. In defining the appropriate corporate structure, electric companies should consider the relationship between the level of regulatory scrutiny, the level of corporate separation, and the company's ability to meet the goals of restructuring. The Department continues to believe that mandatory divestiture of generation or any other category of assets is not desirable or necessary at this time. D.P.U. 95-30, at 24. Nevertheless, the Department believes that voluntary divestiture of generation over time provides the cleanest solution to the problem of inappropriate and anticompetitive affiliate transactions, and that a post-divestiture market structure characterized by arms-length transactions among generators, the ISO, and distribution companies is apt to require the least regulatory supervision. Some of the alternatives presented in the Department's policy and rules on stranded cost recovery would provide incentives for voluntary divestiture of generating assets.

The Department expects that corporate restructuring, coupled with realistic, enforceable ground rules regarding affiliate transactions, can in large measure guard against market power abuse. As noted above, one option for preventing anticompetitive transactions among affiliates would be to require the distribution entities of those electric companies that choose not to divest of generation assets to purchase power for customers from the PE or, after a robust generation market has been established, from non-affiliated sources of generation. In addition, the Department proposes to adopt rules that prevent preferential treatment among affiliates in applying tariffs, disseminating information, and offering services.

A related concern to market power is antitrust issues. Antitrust violations can occur with or without the presence of market power, and the mere presence of market power without evidence of anticompetitive behavior may not necessarily be a violation of law. Ensuring full and fair competition in generation markets requires industry participants to comply with the applicable antitrust laws.[14] Historically, electric companies have been broadly exempted from the operation of such laws by virtue of the state action doctrine.[15] Through its initiative to deregulate the supply sector, the Department seeks to withdraw from its historic function of

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14 The antitrust laws include the Sherman Act, 15 U.S.C. §§ 1-7, the Clayton Act, 15 U.S.C. §§ 12-27, and the Massachusetts Antitrust Act, G.L. c. 93, §§ 1-14A.

15 The State Action Doctrine provides that activities pursued in response to certain directives from a government agency may be exempt from scrutiny from the antitrust laws. Parker v. Brown, 317 U.S. 341 (1943). In California Retail Liquor Dealers Ass'n v. Midcal Aluminum, 445 U.S. 97 (1980), the Supreme Court articulated a two-prong test for invoking the exemption. First, the restraint must be "clearly articulated and expressed as state policy." Second, the activity in question must be "actively supervised" by the state itself. See also D.P.U. 95-30, at 23 n.20. The Department expects and intends that the scope of behavior potentially immunized under the State Action Doctrine will be severely limited in the future.

active supervision, for example in setting rates, and urges electric companies and other market participants to be highly sensitive to the requirements of these laws and the sanctions they impose.

For example, the Sherman Act proscribes certain forms of concerted behavior beyond the level of coordination which is necessary to enable products or services to be available.[16] A group of competitors may not agree (1) not to deal with another,[17] (2) to restrict or withhold a service,[18] or (3) to unreasonably exclude another from membership in that group.[19] Other violations of this law include price fixing, market division, and tie-ins.[20] These are just a few types of anticompetitive behavior which may present unreasonable or per se restraints of trade. Without scrupulous attention by market participants to the laws that identify and redress anticompetitive behavior, the Department's goal of structuring a competitive industry to benefit consumers would be jeopardized. The electric industry must be structured to minimize opportunities for anticompetitive behavior, including behavior violating the antitrust laws. At the same time, the Department intends to adapt its regulatory oversight function in order to maximize the opportunities for full and vigorous competition.

F. Horizontal Market Power

Horizontal market power could arise in the restructured industry from the existence of sufficient concentration in the ownership of generation facilities, transmission facilities, or

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16 National Collegiate Athletic Ass'n (NCAA) v. Board of Regents of the University of Oklahoma, 468 U.S. 85 (1984).

17 Radiant Burners, Inc. v. People's Gas Light and Coke Co., 364 U.S. 656 (1961).

18 FTC v. Indiana Federation of Dentists, 476 U.S. 447 (1986)

19 Northwest Wholesale Stationers, Inc. v. Pacific Stationery & Printing Co., 472 U.S. 284 (1985).

20 A tie-in, or a tying arrangement, exists when the sale or lease of one product or service is conditioned on the purchase of a different product or service. Thus, "[t]he usual tying contract forces the customer to take a product or brand he does not necessarily want in order to secure one which he does desire." Brown Shoe Co. v. United States, 370 U.S. 294, 330 (1962).

distribution facilities to enable one or a few market participants to influence prices inappropriately. In order to minimize the potential for abuse of horizontal market power, (1) prices must be clear and transparent and market information for present and future transactions must be readily available; (2) spot and forward markets accessible to all participants must be allowed to develop; and (3) rules and regulations must be applied in a fair and consistent manner to enable market participants to compete based on efficiency and productivity. D.P.U. 95-30, at 21.

As the market evolves, there will be a continuing need to assess the degree to which competition is indeed "full and fair," and the Department will take whatever steps are within its jurisdiction to prevent abuses of market power. For example, it may be appropriate to minimize opportunities to develop an excessive concentration of generation ownership. Options for limiting the concentration of generation ownership include establishing a certain threshold of concentration that would trigger a review of market power, or encouraging FERC and the Securities and Exchange Commission to require divestiture of generation assets if a proposed merger would result in the merged entity owning more than a certain percentage of the generating capacity in the New England market. At the same time, such guidelines should not be unnecessarily intrusive and should allow mergers, acquisitions, and other forms of reorganization to go forward without delay where such transactions are consistent with the public interest. Mergers and Acquisitions, D.P.U. 93-167-A (1994). We will be particularly interested in whether such transactions lead to significant increases in market power.

The Department seeks comments on methods for establishing an appropriate threshold measurement of market power in Massachusetts and in New England, on the applicability of the Hirschman-Herfindahl Index ("HHI"),[21] and on the appropriate definition of the market

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21 The Hirshman-Herfindahl Index provides a measure of the degree of concentration in ownership at a particular level of production of a market good (e.g., ownership of generation units). It is calculated by summing the squares of the market shares of each firm in the market. As a general rule, the United States Department of Justice has (continued...)

(e.g., geographic area, generation capacity by type, etc.) for calculation of the HHI, if applicable. Finally, the Department invites comments on the most appropriate mechanisms within our jurisdiction to prevent abuse of horizontal market power, on how these mechanisms can be established, and on ways to maintain flexibility so that these mechanisms can be altered as the market develops.

G. Municipals

In D.P.U. 95-30, the Department was silent with respect to the level of involvement of municipal light departments ("municipals") in the restructuring process. This silence reflects the distinct difference between the Department's statutory authority in regulating municipals as compared to investor-owned utilities ("IOUs"). Although the Department does maintain some oversight over municipals, that authority is not as extensive as our authority over the activities of IOUs. See Newbay Corporation, D.P.U. 88-265, at 17-18 (1994) ("Newbay") for a discussion of the differences in statutory authority.[22]

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found that markets with HHI values lower than 1800 are only moderately concentrated while those with HHI values above 1800 are considered highly concentrated. U.S. Department of Justice and Federal Trade Commission Horizontal Merger Guidelines, April 1992. Testimony presented by Massachusetts Electric Company in its February 1996 filing states that HHIs for the NEPOOL generation market are above 1800 for both summer and winter capacity ratings (Testimony of R.J. Gilbert at 25). Although Gilbert claims that there are other factors to mitigate concern with market concentration in NEPOOL, the existing concentration appears sufficiently high to warrant attention.

[22] In Newbay, the Department stated:

> The general statutory scheme of G.L. c. 164 which governs the Department's authority over IOUs and municipal light plants distinguishes between the two. See, e.g., G.L. c. 164, § 1 (definition of electric company does not include municipals); G.L. c. 164, § 76 (source of supervisory authority over IOUs generally inapplicable to municipals); 220 C.M.R. §§ 8.00, 9.00, 10.00 (resource acquisition regulations applicable only to IOUs). Compare G.L. c. 164, § 94 (granting IOU ratemaking authority to Department) with G.L. c. 164, §§ 58-59 (empowering Department to investigate discriminatory rates of municipal light departments without granting ratemaking authority). There are, however, areas where the statute and regulations apply equally to municipals and IOUs. See G.L. c. 164, § 69G(4) (definition of electric company under statutes pertaining to construction of jurisdictional facilities and forecast/supply

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In written comments submitted to the Department in D.P.U. 95-30, various municipals argued that the Department lacks jurisdiction to impose certain restructuring policies upon municipal utilities, such as retail wheeling, rate unbundling, and forced divestiture of assets. See, e.g., Initial Comments of the Massachusetts Municipal Light Plants at 52-55, 61-64. However, for purposes of this rulemaking, it is not necessary to delineate the Department's jurisdiction with respect to municipals. Rather than impose any changes on municipals that might be interpreted as an expansion of the Department's authority, the Department intends to preserve the current jurisdictional bounds, while encouraging municipals to participate voluntarily in the future restructured electric industry.[23] Because municipals are governed by

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plans includes municipals); G.L. c. 164A, § 9(b)(1)(iv) (making provisions of G.L. c. 164, § 71-74, 76, 87-88, 90-91 applicable to municipal light department members of the New England Power Pool with respect to electric power facilities); 220 C.M.R. § 25.00 (billing and termination regulations expressly apply to IOUs and municipals).

In addition, the statutory framework and judicial interpretation of that framework indicate that the Department ought to defer to the judgment of elected municipal officials in many matters pertaining to management of municipal light plants. See G.L. c. 164, § 56 (indicating municipal light plant manager responsible for operation and management under direction of local officials); Board of Gas and Electric Commissioners of Middleborough v. Department of Public Utilities, 363 Mass. 433, 438 (1973) (special provisions of G.L. c. 164 applicable to municipal light boards indicate legislative deference to rates fixed by public officers acting under legislative mandate). The Department does, however, have review authority over certain actions of municipal light plants and, while it will defer to the judgment of municipal officials, the Department cannot ignore its oversight responsibilities. See Bertone v. Department of Public Utilities, 411 Mass 536, 548 (1992) (light plant discretion to alter rates not unlimited and Department has statutory power to regulate); Holyoke Water Power Company v. Holyoke, 349 Mass. 442, 446-447 (1965) (Department has substantial supervisory powers over municipally-owned plants).

23 See Stow Municipal Light Department, D.P.U. 94-176, at 43 (1996) (Department applied principles of D.P.U. 95-30 to a dispute between two municipal light plants, involving the statutory determination by the Department of the property and price to be included in the acquisition of one town's plant by another; Department stated that "[a] fair and logical policy regarding stranded costs requires that municipal electric systems be treated similarly to investor-owned utilities, except where substantial differences
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local officials who are accountable to their resident customers, those elected local officials should determine the extent of the involvement of municipal utilities in a restructured, competitive industry. At the same time, we do not want to foreclose or inhibit any opportunities for these utilities, and we must be mindful of the interests of those retail customers of municipal utilities who in the future may wish to obtain direct access to the competitive, regional market for power. We therefore seek to create an environment that allows municipals to participate in a restructured industry on an equivalent basis to that of the IOUs. For example, if a municipal wants (and is authorized) to sell power to an IOU's customers, the Department would require the municipal to offer that IOU reciprocal access to its customers.

The Department is interested in receiving comments, particularly from municipals, on this issue and on the following specific questions:

1. As the restructuring process moves forward, what restructuring policies pose the most significant implications for municipal light departments?
2. How do municipal light departments see themselves participating in, or adapting to, the restructured industry?
3. What policies should be adopted by the Department to provide municipal light departments with the best opportunity to integrate their activities effectively with those of a restructured electric industry, and, thereby, provide their customers with the benefits of competition?

H. Load Aggregators

In a restructured electric industry, there will likely be an increasing number of generators, load aggregators, marketers, and brokers, which may combine groups of customers and match them with the available supply of generation. The market will eventually exhibit a multitude of combinations of customer groups, of supply portfolios, of customer-specific levels of reliability, and of payment terms and conditions.

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warrant different treatment").

With the entrance of new players comes the possibility that some may seek to take unfair advantage of customers, especially during the transition to a fully mature market. Therefore, it is prudent to institute basic informational registration requirements on generators, aggregators, marketers and brokers. In the interest of ensuring that the barriers to entry for new players in the market are minimized, the Department seeks to avoid undue regulatory burdens. The limited regulations that would establish registration requirements are included in the draft rules at Section 11.07, within Attachment A.

We invite responses to the following questions:

1. Are the proposed registration requirements sufficient or should the Department require additional indicators of financial and managerial ability, or the posting of surety bonds, etc. If so, what should those requirements be?

2. What safeguards can be used to protect against "slamming" (transfer of a customer to another provider without authorization by or notification to the customer)?

I. Environmental Issues

Since the Department stated in D.P.U. 95-30 that restructuring plans should support and further the goals of environmental regulation, there has been increasing attention nationally, and in particular in New England, to the potential environmental impacts of restructuring the electric industry. The combination of industry restructuring efforts and the existing differences among states in emissions control requirements have led to concerns that, with restructuring, the Northeast may bear disproportionate environmental impacts relative to other regions of the country, and that states in the region may have greater difficulty complying with the Clean Air Act. The Department notes that FERC Order 888 adopts the finding of the Final Environmental Impact Statement, issued April 12, 1996, that there is likely to be minimal environmental impact arising from the implementation of open transmission access, at least in the near term. Nevertheless, the Department anticipates that the potential environmental impacts of electric industry restructuring efforts at the state and federal levels will be a source of continuing concern until and unless they are addressed satisfactorily by the appropriate jurisdictional authorities. There is a compelling need for regional coordination among utility and environmental regulators in order to minimize any potential negative environmental impacts of electric industry restructuring.[24] The benefits of introducing greater competition into the electric industry will be diminished if restructuring efforts are not consistent with achievement of environmental quality goals. The Department seeks to establish economic regulatory policies that are consistent with other efforts at the state, regional, and federal levels to achieve environmental quality goals in a restructured electric industry.

Environmental regulators are taking steps to ensure that the environmental impacts of the electric industry are not exacerbated by a failure to be responsive to changes in the industry. For example, Massachusetts has recently signed the memorandum of understanding among states in the Ozone Transport Region establishing a trading program for emissions of nitrogen oxide ("NO_x"). In addition, the Commonwealth of Massachusetts Department of Environmental Protection ("DEP") has stated its intent to pursue a two-pronged approach, including efforts to promote similar standards for like generators in other regions and to ensure that generators under its jurisdiction take appropriate steps to minimize environmental impacts from restructuring (see Letter from DEP Commissioner Struhs to electric companies, February 2, 1996). The Department supports the efforts of the U.S. Environmental Protection Agency ("EPA"), DEP, and the coordinated efforts of environmental regulators in the region to ensure that like generators will be subject to similar environmental standards and to foster market-

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[24] This is consistent with the responses of many government agencies to the FERC Draft Environmental Impact Statement (issued November 17, 1995) on its proposed open access policy. Governors, public utility commissions, departments of environmental protection, and attorneys general from many states in the Northeast filed comments stating the importance of a level playing field among competitors, and encouraging cooperation between state and federal regulators and between environmental and utility regulators. Similarly, resolutions by the National Association of Regulatory Utility Commissioners (NARUC) and the New England Governor's Conference (NEGC), as well as comments from the U.S. Environmental Protection Agency to FERC, reveal a clear desire for initiatives in both environmental and utility regulatory spheres to minimize the environmental impacts of restructuring.

based approaches to achieving environmental goals.[25] The Department encourages the inclusion of voluntary emission reduction provisions in electric company restructuring plans. These efforts are consistent with the Department's goals of ensuring full and fair competition, and applying the rules to all competitors equally. Regional environmental policies also will ensure that states in the region are proceeding at a consistent pace in addressing environmental impacts. The Department will take steps within its jurisdiction, including participation in coordination activities through the New England Conference of Public Utility Commissioners and the National Association of Regulatory Utility Commissioners ("NARUC"), to secure continued progress toward cost-effective achievement of environmental quality goals.

The Department also remains interested in exploring what it can do to encourage or create a more level playing field among existing and new sources of generation. The Department would support a process wherein an existing generating unit would have to achieve compliance with new source performance standards within three years of its original retirement date if it will operate past that date. The Department recognizes that establishing this process may not be within our jurisdiction and seeks comments on what it can do to support environmental regulators in such an effort. The Department also invites comments on the costs and feasibility of implementing this approach.

In the interest of establishing a level playing field in generation, the Department has previously determined that electric companies will not be allowed to collect going-forward costs for environmental compliance in their stranded cost recovery mechanisms.[26] Instead, all

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[25] Coordination efforts include the Ozone Transport Commission, the Ozone Transport Assessment Group, and the North East States for Coordinated Air Use Management (NESCAUM).

[26] Some electric companies in their February 1996 filings proposed to include going-forward environmental compliance costs in a stranded cost recovery charge. However, in D.P.U. 95-30, at 32, the Department did not include environmental compliance costs in its definition of stranded costs and clearly stated that its definition of stranded costs "applies only to costs and commitments incurred prior to [August 16, 1995]." See also Environmental Externalities, D.P.U. 91-131, at 114 (1992) (the

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plant owners should bear the going-forward costs of existing requirements as well as the risk of future environmental controls. The Department notes that environmental requirements are becoming increasingly stringent as demonstrated, for example, by EPA's upcoming standards for NO_x and small particulates, as well as the possible standards on toxics pursuant to the Clean Air Act Amendments of 1990. We expect that generators will anticipate and minimize compliance costs as they seek to become and remain competitive in an unregulated generation market.

During the transition, the Department's proposed policies will encourage low environmental impact resource options like renewables and energy efficiency in order to offer these options a meaningful chance to compete. This could be done through programs that provide transitional support to renewables and through energy efficiency efforts that are consistent with the Department's goals for the transition. For further discussion of renewables and energy efficiency, see Sections V.B. and V.C., below.

The Department requests comments on the following question (please see also question number 5 in section III.B.2. "Additional Responsibilities of the ISO"):

1. Would it be feasible to implement a policy whereby an existing generating unit would be required to achieve compliance with new source performance standards within three years of its original retirement date if it will operate past that date? What costs would be involved? What would the role of the Department be in supporting relevant environmental agencies in implementing such an approach?

J. Distribution Franchise

The Department has recognized in the past that utilities have certain rights and obligations within their service territories.[27] Historically, each of the Commonwealth's

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Department found "that project proponents, not ratepayers, should assume the risk of future environmental regulation and must bear the costs of compliance with such regulation"), rev'd and rem'd on other grounds Massachusetts Electric Company v. Department of Public Utilities, 419 Mass. 239 (1994).

[27] See Interim Order Initiating Integrated Resource Management Process, D.P.U. 86-36-A (continued…)

investor-owned utilities has distributed electricity over clearly defined service territories. D.P.U. 95-30, at 5. However, it is not clear that the utilities have exclusive franchises. Id. at B.9.

Many of the current features of utility operations will continue to exist for distribution companies, at least for the transition period. For instance, the market structure envisioned in D.P.U. 95-30 anticipated that the transmission and distribution of electricity will remain monopoly services, and will thus continue to require regulatory oversight. Id. at 28. In addition, the obligation to promote selected public policy goals (e.g., protection of low income customers, energy efficiency), and the obligation to provide the public with non-discriminatory service at reasonable rates will be part of the role of distribution companies. Some of these continuing functions may be transformed during the transition (e.g., the obligation to serve will be transformed into an obligation to provide Basic Service, see proposed rules, 220 C.M.R. § 11.05, attached).

Clearly, the restructured distribution companies will inherit many features from their predecessor utilities. The Department's goal of ensuring a smooth transition will be furthered by building on the base of existing, clearly defined service territories served by restructured distribution companies. Existing franchises may not be exclusive as a matter of law. However, as a matter of general policy, we propose to hold existing distribution service territories intact as we proceed through the transition. We suggest that the most expeditious way of implementing the policies reflected in this explanatory statement is to treat the service territories as exclusive, at least through December 31, 2007.[28] The retail distribution of

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at 5 (1987); Western Massachusetts Electric Company, D.P.U. 84-25, at 34-35 (1984).

28 This assumption of territorial exclusivity would not preclude opportunities for parties to engage in self-generation, which is a right shaped by federal law. It would, however, preclude customers situated at distribution companies' territorial borders from seeking service from neighboring distribution companies unless consistent with Department precedent or mutually agreed upon by both distribution companies for reasons of cost
(continued…)

electricity will remain a monopoly service offered exclusively by the local distribution company. When distribution rates become unbundled, it is possible that other functions at the distribution level will be offered by competitive markets.[29]

In a restructured electric industry, distribution companies will generally be discouraged (if not prohibited) from owning and operating generation facilities directly. The Department will continue to require distribution companies to provide least-cost distribution service, although that requirement will be implemented through performance-based regulation. In order to encourage the most efficient use of a distribution system, when there are opportunities to reduce or avoid distribution upgrade costs through distributed generation and targeted demand-side management, a least-cost approach might require a distribution company to locate appropriately-sized generation or demand-side management ("DSM") in distribution-constrained areas.

In implementing the Public Utility Regulatory Policies Act ("PURPA"), the Department has provided that qualifying facilities ("QF") that have a capacity of 30 KW or less shall have the option to run their meters backwards in order to receive payment for the power generated at the retail sales rate of their electric company.[30] See 220 C.M.R. 8.04(2)(c). A number of residential, and other, customers have taken advantage of this regulation to install small power and cogeneration facilities. We anticipate that others would be interested in installing similar units in the future. However, the Department questions whether it would be appropriate to pay (through net billing) for generated power at a rate that encompasses costs for generation,

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or convenience.

29 For example, such functions as billing, metering, coordination with aggregators, provision of backup or Basic Service may, in time, be served competitively.

30 When more electricity is generated by a QF than is consumed on premises, the excess electricity flows out of the premises and into the electric company's distribution lines, causing the meter to run backwards and to register a decrease in the kilowatthours used for billing purposes.

transmission, and distribution. We solicit comments regarding whether there may be a need for a change in regulation to provide for payment to the QFs at the market price for generation rather than the retail sales rate. Note that renewable energy resources are discussed in Section V.C, below and Section 11.08 of the draft rules.

The Department solicits comments on these issues and also poses the following questions:

1. Should a prohibition against distribution companies owning generation directly apply to small-scale generation delivering power of distribution-level voltage owned for the purpose of avoiding distribution system upgrade costs (i.e., distributed generation)?[31]

2. Should distributed generation be supplied by the distribution companies or through competitive means?

3. Can distributed generation be supplied by both distribution companies and competitive entities?

4. Which functions of a distribution company should remain within the scope of a monopoly franchise and which are more appropriately provided by competitive markets?

5. Should the Department pursue legislation to (1) define the rights and obligations of the new distribution companies, and (2) define or increase the Department's authority to establish distribution company rights and obligations? If so, what should be the content of the proposed legislation?

K. Universal and Basic Service

The Department reiterates its position that electric service is essential and should be available and affordable to all customers. D.P.U. 95-30, at 16. All customers should have the opportunity to enjoy the benefits of competition. Id. at 15, 19, 25. Under the existing regulated industry structure, electric companies have an obligation to serve all customers. Id. at 25. In addition, residential customers who meet certain eligibility criteria receive discounts off their base rates. Id. Furthermore, there are certain explicit protections that ensure that

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[31] Consider the effects of this question on corporate structure as discussed in Section III.E, above.

electricity is available to customers whose health and safety could be jeopardized by their inability to pay the full cost of electric service. Id.; see also 220 C.M.R. §§ 25.00 et seq.

The new industry structure must provide a level of protection for low-income customers equivalent to that provided within the current industry structure. D.P.U. 95-30, at 25. Following is a discussion of (1) Universal Service, which under our proposed rules is defined as electric service provided by a distribution company at a discounted rate for qualifying low-income residential customers and (2) Basic Service,[32] which is defined as electric service provided by a distribution company to a customer who chooses not to obtain or is unable to obtain electricity from a supplier, or whose supplier fails to provide generation service.

1. Universal Service

Currently, all electric utilities offer discounted rates to residential customers who meet eligibility requirements set forth in their tariffs. Typically, these tariff provisions require that a low-income discount customer (1) must be the head of a household or principal wage earner, and (2) must be currently receiving: (a) Supplemental Security Income from the Social Security Administration; or (b) Aid to Families with Dependent Children, Emergency Aid to Elderly, Disabled and Children, Refugee Assistance, Medicaid, or Food Stamps from the Massachusetts Department of Public Welfare; or (c) Veteran's Services Benefits from the Massachusetts Veterans Services Administration; or (d) Low Income Heating Energy Assistance Program ("LIHEAP") services from a certified Community Action Program Agency.

In a restructured industry, consistent with the principle of universal service, distribution companies would be required to continue to offer discounts to eligible customers. The Department's view is that the eligibility criteria for low-income rates should remain the same.

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[32] In D.P.U. 95-30, at 16, 25, under the principle of the provision of universal service, the Department stated that each distribution utility must continue to have an obligation to connect all customers in its service territory to the distribution system. The Department addresses this requirement under our discussion of Basic Service.

That is, the total low-income subsidy should be the same as the subsidy provided under each distribution company's low-income tariff as it exists on the effective date of the final rules. The low-income discount would apply to the distribution and transmission component of a customer's bill. During the transition period, the discount also would be applied to the stranded cost charge. The distribution company would allocate the total subsidy associated with the provision of low-income rates to all rate classes based on a rate base allocator, and recover the amount allocated to each class via a non-discriminatory, non-bypassable general access charge.

The Department's Billing and Termination regulations for residential customers, 220 C.M.R. § 25.00, currently provide, among other things, (1) the opportunity for an informal hearing to dispute billing and termination problems, and (2) termination protection during the heating season for residential customers with financial hardships, customers with a serious illness or an infant, and elderly customers. In the restructured electric industry, the Department's view is that these regulations should continue to be in effect, and should apply to the distribution company providing monopoly services under the Department's jurisdiction.

2. Basic Service

Under the current regulatory structure, electric utilities have an obligation to serve any customer who requests service within the utility's service territory. In the new electric industry, each distribution company must continue to have an obligation to connect all customers in its service territory to the distribution system and to provide distribution service. In addition, the distribution company will be required to provide Basic Service to all customers in its service territory (1) who choose not to contract directly for electricity with a supplier (2) who cannot obtain power in the open market or (3) whose supplier fails to provide generation service. In this way, Basic Service will insure that no customer goes without electricity. The Billing and Termination protections pursuant to 220 C.M.R. § 25.00 will continue to apply to residential customers receiving Basic Service.

Consistent with the Department's view regarding the market structure for the electric industry, under one alternative of the Department's proposed rules, distribution companies with affiliated generation companies would be required to purchase generation supply for Basic Service from the PE, and to price the generation component of such service to customers at the spot market price.[33] Under a second alternative, distribution companies with affiliated generation companies may provide generation supply for basic service from any source. However, in the second alternative, the terms and rates for such service would be subject to Department review and approval. Under either alternative, distribution companies without an affiliated generation company may provide generation supply for Basic Service from any source.

Under our proposed rules, customers may request basic service from their distribution company at any time. The Department will not impose any restriction on the number of times that customers may exit from and return to Basic Service.[34] This is not to say, however, that contracts for generation service between customers and suppliers may not establish different terms for service, including restrictions on how and when a customer may terminate service. Further, under our proposed rules, the supplier must notify the distribution company if such supplier is unable to provide generation supply. The distribution company, in turn, must notify the affected customer of such failure. The Department seeks comments as to the frequency with which customers may change suppliers and the manner in which such changes will be coordinated, e.g., through an ISO, by the distribution company, or by some other means. In other words, what procedures are needed to implement Basic Service most

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33 At the outset, the spot market may be limited in scope or pricing arrangements. Therefore, the distribution company would procure electricity for its basic service through competitive bidding for short-term wholesale contracts, and pass the costs through to the Basic Service customers.

34 This freedom of choice should not present a hardship for distribution companies, since they will not be exposed to the risk of owning or contracting for such power; all costs would be billed in full to customers. However, the Department solicits comments on this point.

effectively, and which entity or entities should be responsible for notification of a change in supplier or the failure of a supplier to provide generation supply? See proposed rules, 220 C.M.R. § 11.05, attached.

IV. IMPLEMENTATION: BY JANUARY 1997

A. Overview

In Section III, above, the Department outlined its concept of a future industry structure based upon a competitive market for generation, and stated its intention (1) to remove all regulatory barriers in Massachusetts to such a market structure by January 1, 1998, and (2) to work with state and federal authorities to see that such a regional market structure becomes a reality. The Department recognizes, however, that a rapid movement from the current industry structure to a new industry structure may produce customer confusion and concern. We are committed to ensuring that the transition to a new industry structure proceeds as smoothly as possible for the electricity consumers of the Commonwealth.

Implementation of unbundled rates for all electric companies is a necessary prerequisite to move to a restructured industry. In D.P.U. 95-30, at 47, the Department directed electric companies to file illustrative rates and supporting information that, at a minimum, indicate unbundled charges for generation, distribution, transmission, and ancillary services.

Boston Edison Company ("BECo") proposes to combine the unbundling of customer bills with proxy market pricing in 1997 as a way of preparing the company and its customers for the market structure changes that it expects will be implemented as early as 1998. BECo calls this 1997 proposal E-Plan Phase 1 ("Phase 1") (BECo Industry Restructuring Proposal at 47). BECo asserts that the Phase 1 plan can be implemented before key details on market structure are resolved, including NEPOOL reform and resolution of FERC open access issues (id.). The Department believes that the basic concept behind BECo's proposal -- implementation of an unbundling/market proxy plan -- if implemented for all customers of the Commonwealth, may indeed ease the transition to a new market structure.

B. The Boston Edison Plan

The first component of BECo's proposal is the implementation of unbundled rates by January 1, 1997 (id. at 49). By that date, customers' rates would be separated on bills into network services and energy services. Network services would include both the costs of the transmission and distribution system, and the stranded cost, or access charge. The transmission and distribution portion would be initially based upon current rates, and would be subject to a performance-based rate structure (id.). The access charge would be consistent with BECo's stranded cost calculation, but would also include an additional component that BECo states would be necessary to cover the cost of generation that may be critical to sustain transmission support in the region (id. at 50).[35]

BECo proposes to price energy services based on a proxy New England Regional Market Price Index ("NEMPI"). This hourly calculation would include (1) the marginal fuel and variable operating cost of the most expensive generating unit running in the New England region in that hour ("Marginal Energy Cost"), (2) the start-up, shut-down, and no-load costs[36] of the most expensive unit running in that hour (the total is termed "No-Load Costs"), and (3) the loss-of-load probability ("LOLP") in that hour times the value of loss-of-load ("VLL") ("Capacity Cost").[37] Id. at 55.

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35 To calculate this adjustment, BECo identifies a revenue shortfall as the difference between forecasted revenues received from the new rate structure, and forecasted revenues assuming the existing rate structure (BECo Industry Restructuring Proposal at 50-51). BECo does not explain how this calculation can be attributed to network transmission support.

36 BECo states that no-load costs represent the fuel costs incurred to keep a unit available in a given hour. The total for No Load Costs for a unit is divided by the unit's total production during on-peak hours to derive a dollar-per-kilowatthour ("KWH") value (BECo Industry Restructuring Proposal at 55-56).

37 LOLP is the probability that capacity will be inadequate to meet demand in a given hour due to unexpected load increase or failure of a generation unit. This value is calculated by the production cost simulation model. VLL is a measure of the price customers are willing to pay to avoid a loss of supply, and is an input to production cost simulation (The value is set by BECo at $6/KWH.) (BECo Industry Restructuring

(continued...)

BECo would project the NEMPI one day ahead, and would calculate an actual NEMPI after-the-fact for each hour, using a production costing model ("PROSYM"), which simulates a power system's hourly operation given key inputs such as system load and generating unit data (id. at 56). Customers with hourly metering would be billed based on the actual NEMPI for each hour; customers without hourly metering would be billed based upon an appropriately weighted monthly or yearly average of the actual NEMPI values (id. at 59). BECo states that, given the confidential nature of important generating unit data, these calculations would best be performed by NEPEX, the only entity in the region with access to such data. Short of this, however, BECo states that it will develop and publish the NEMPI using reasonable estimates and after-the-fact load and generation data (id. at 58).

The Department is very interested in the concept behind the BECo proposal as an initial step in reforming the electricity marketplace -- that is, the unbundling of rates on customer bills and the pricing for energy services at some index of regional marginal generation cost. The Department believes there would be substantial educational value to all customers of electric companies in Massachusetts from the implementation of this model in each company's service territory for some period of time before full direct access is implemented. Customers would become familiar with an unbundled bill format and the movement in the cost of electricity in a competitive market. Consequently, the Department proposes to require implementation of rate unbundling and energy services pricing for all companies as close to January 1, 1997, as possible. Each of these components is discussed in the sections that follow.

1. Unbundling Rates

In D.P.U. 95-30, at 16, the Department stated that the "functional separation of generation from transmission and distribution services is a necessary first step to address

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Proposal at 55-56).

market power issues and limit a company's ability to provide itself an undue advantage in buying or selling services in competitive markets." As indicated above, the Department continues to believe that the functional separation of services offers the minimum acceptable approach to address the potential for anticompetitive behavior in a market where utilities may continue to have vertical and horizontal market power. At the outset, these unbundled rates will serve to educate customers about the various services (e.g., distribution, transmission, generation) now offered by the distribution company as well as the pricing of such services.

Unbundling, or the design of rates that reflects the cost of providing each component of functionalized service, is a first step for electric utilities in restructuring their services to support competition as it develops in the generation market. The unbundling of rates can proceed independently of full competition in the generation market, complete open-access and non-discriminatory transmission, or a fully restructured electricity market. The structure of unbundled rates during the transition period should evolve in a manner consistent with the dynamics of the changing marketplace, the transition principles, and the principles for a restructured electric industry specified in D.P.U. 95-30.

Rates are currently structured according to methods developed over the years by the Department. These methods for cost functionalization, classification, allocation, and design of rates reflect cost incurrence. See, e.g., Massachusetts Electric Company, D.P.U. 95-40, at 144-145 (1995); Boston Gas Company, D.P.U. 93-60, at 331-332 (1993); Cambridge Electric Light Company, D.P.U. 92-250, at 163-164, 194-195 (1993); Western Massachusetts Electric Company, D.P.U. 91-290, at 44-45 (1992). The Department, at this time, does not anticipate any major departures from these rate structure methods.

Regarding the functionalization of a utility's services into the components of generation, transmission, and distribution, the Department in 220 C.M.R. §§ 51.00 et seq. has adopted the uniform system of accounts for electric utilities promulgated by FERC as a basis for cost functionalization. Department precedent shows that electric utilities over the years have complied with this system of accounts. We do not see at this time any reason to modify this regulation.

Similarly, the methods for classification and allocation of utility costs, including the methods for the design of rates, have evolved over the years through the consistent application of Department rate structure goals of efficiency, fairness, simplicity, continuity and earnings stability. In the process of unbundling the rates during the transition period, the Department expects electric utilities to continue to adhere to these methods in order to achieve the Department's rate structure goals.

The Department notes that to the extent the evolving market necessitates changes or refinements to these existing rate structure methods, we are open to general suggestions or company-specific proposals for modifications to improve or refine them for reflecting the incurrence of costs.

The Department reiterates its directive in our March 15, 1996 procedural ruling that every electric utility file revenue-neutral, unbundled rates by October 7, 1996, in order to facilitate the expedient and orderly transition to competition in the generation market and to achieve the Department's primary objective of reducing the cost of electricity over time for all ratepayers. We expect that for most companies, depending on the required level of review, such unbundled rates will be implemented by January 1, 1997, but not later than March 31, 1997.[38]

2. Energy Services Pricing

The BECo plan envisions the publication of a regional index for projecting the hourly price of energy one day ahead of time, as well as a calculation of actual hourly prices after the fact. The Department believes that implementation of such pricing will provide substantial educational benefit for electricity customers, and may provide an opportunity for some

[38] With the implementation of performance-based rates, electric companies will have an opportunity to file new costs of service.

customers to enter into contracts for differences and achieve actual savings in 1997. Consequently, the Department will require that electric companies implement energy pricing similar to that proposed by BECo beginning on January 1, 1997. The Department requests comment on how best to implement this, and in particular on the following questions:

1. Would implementation of an unbundling/market proxy plan (such as that proposed by BECo) in 1997 by all Massachusetts retail distribution companies significantly change what otherwise would be the dispatch order of generating units in New England? Why? What implications, if any, would this have for the practicality and desirability of implementing this plan? What implications, if any, would this have for the collection and mitigation of stranded costs?

2. Would an unbundling/market proxy plan in 1997 allow and encourage the development of contracts for differences during 1997? Please explain how. How might the design of the plan affect the likelihood that customers would enter into such contracts?

3. Would an unbundling/market proxy plan in 1997 require the publication of a projected and an actual NEMPI by NEPEX? What would be the benefits and drawbacks of NEPEX calculating the projected and actual NEMPI ? If not done by NEPEX, how would Massachusetts companies develop and publish an equivalent NEMPI on their own?

V. IMPLEMENTATION: OTHER ISSUES

A. Stranded Cost Recovery

1. Introduction

In D.P.U. 95-30, at 29-31, the Department stated that electric companies should have a reasonable opportunity to recover net, non-mitigable stranded costs, and that companies must take all practicable measures to mitigate such costs. The Department concluded in that Order that the bulk of stranded cost recovery could be completed within five years, and in no case should stranded costs be collected for more than ten years. The Department required that proponents of stranded cost recovery demonstrate how stranded cost recovery mechanisms would facilitate electric industry restructuring that is in the public interest. The Department did not, however, specify how such costs should be calculated and presented to the Department for review.

In this statement, the Department expands upon the principles presented in D.P.U. 95-30 with respect to the calculation, mitigation, and collection of stranded costs. In particular, the Department sets forth draft rules regarding the elements and format of company stranded cost calculations, and poses questions regarding the application of certain incentive mechanisms. The Department's intention is to provide electric companies a reasonable opportunity to recover stranded costs in a manner that will promote long-term benefits to electricity consumers in the Commonwealth. Here, the Department summarizes possible incentive mechanisms that could apply to the collection of stranded costs, and outlines the major components of the proposed rules at 220 C.M.R. §11.03, setting forth calculation and filing procedures. The Department also discusses the treatment of stranded costs associated with nuclear generation facilities.

The Department outlines a stranded cost recovery mechanism that allows for either an administrative determination or market valuation of generating assets, or a combination of the two. We recognize that administrative determinations of future costs and load forecasts have often turned out to be inaccurate. Therefore, we have proposed a reconciliation method to correct for major errors in projections of future market conditions. We also recognize, however, that market valuation of generating assets raises the possibility that customers will pay twice for existing generation -- once through an inflated stranded cost charge, and then again through higher market prices for power generated by these same assets in the future. Therefore, a measured approach to the sale of assets is a goal of the incentive mechanisms/options we propose below.

2. <u>Public Policy Incentives</u>

The Department's policy on stranded costs provides companies a reasonable opportunity to collect costs associated with previously incurred commitments, in a manner that benefits the consumers of Massachusetts by promoting (1) the aggressive mitigation of stranded costs, (2) the encouragement of clean, efficient generation, and (3) the development of an industry structure that will maintain the lowest possible electricity costs in the long run. As the Department has discussed in detail in Section III, above, these objectives will be met only if the electricity market of the future includes a competitive market for generation -- a market of many buyers and sellers, arms-length transactions, equal access to information, and low thresholds for entry.

The Department is interested in receiving comments on structuring recovery of stranded costs in a way that provides a meaningful reward for company actions that will increase the competitiveness of the generation market as soon as is practical. In the Department's view, continued utility ownership of generation in conjunction with full recovery of embedded costs during the transition raises concerns about the development of a robust competitive market for generation. If imperfect competition is the result of imperfect industry restructuring -- that is, if consumers pay more for stranded costs than they should, and pay market prices for generation -- consumers risk paying higher prices than under the current system of direct price regulation, and may face fewer choices in what would be an anemic generation market.

As noted in Section III.E, above, the Department continues to believe that mandatory divestiture of generating units is not desirable or necessary at this time. However, we want to explore options that would encourage the voluntary divestiture of generation assets during the transition to a restructured industry, but that encourage divestiture in a manner, and at a pace, that is in the public interest. Although significant divestiture over time may be critical to achieve the Department's long-run goals, we recognize that a hasty divestiture of generation assets may have an adverse impact on costs to customers. Should stranded costs be set based on depressed asset values, ratepayers may face inappropriately high stranded cost charges and the possibility of paying higher market prices for power generated by these same assets in the future. One way to avoid this potential outcome might be to require contracts for power generated from divested plants with the distribution affiliate of the company that sold the generating assets. The contract terms would coincide with the period for recovery of stranded costs to ensure that customers pay no more overall than the embedded cost of generation. The Department invites comment on the advantages and disadvantages of this type of arrangement. We are particularly interested in whether requiring contracts with divested generators raises the same anticompetitive concerns that divestiture is in part meant to address.

The Department is mindful of the fact that any mechanism that presents utilities with a choice between either divesting generation and obtaining maximum stranded cost recovery, or retaining ownership of generation and possibly absorbing some portion of these costs, still must afford a reasonable opportunity to recover stranded costs. Consequently, the Department will consider various mechanisms for company collection of stranded costs (1) that will encourage a measured divestiture of generation assets over a period of time, (2) that will not depress the market value of such assets, or be otherwise unduly disruptive to the generation market, and (3) that provide electric companies a reasonable opportunity to recover their stranded costs.

It is the Department's intention to determine, over the course of this proceeding, whether there is an appropriate mechanism, or combination of mechanisms, that could accomplish these objectives. If so, the Department will include such mechanisms in the final rules at 220 C.M.R. § 11.03(3)(a)(iv). Unless a mechanism that better accomplishes the Department's goals (as discussed above) is presented by parties in a settlement or identified through the course of this proceeding, the Department will consider one or a combination of the following three options:

(1) The Department could impute a full equity return on company-owned generation in the calculation of revenue-neutral rates for 1997, but impute a gradual decline in return on equity for these assets over time.

(2) The Department could apply a graduated incentive for company divestiture of generation assets. The graduated incentive could consist of a percentage adjustment to calculated stranded costs that increases over time through the transition period. The level of the adjustment would be tied to the extent to which the company has retained ownership of generation.

(3) The Department could provide for reconciling and non-reconciling components of stranded cost recovery, with the relative size of the components tied to the amount of generation divested by the company (e.g., the more generation divested, the larger the reconciling component).

The Department expects that implementation of an incentive structure that encourages voluntary divestiture of generation over time, in combination with the affiliate transaction policy outlined in Section III, above,[39] can achieve the Department's restructuring goals discussed earlier in this Section. This recovery structure may also protect the interests of Massachusetts' ratepayers by addressing the significant residual value that companies would derive from continued ownership of generating units after they have recovered their allowed stranded costs.[40] The Department invites commenters to address the mechanisms outlined above, and to propose alternatives that may better achieve the Department's objectives.

3. Stranded Costs of Nuclear Generation

Nuclear units have unique costs and uncertainties associated with their operation, reliability, safety, decommissioning, and issues related to liability. The Department does propose to allow collection of nuclear decommissioning costs for the entire lifetime of the original operating license. See 220 C.M.R. § 11.03(3)(a)(iv). However, the special nature and problems of nuclear facilities raise the question whether stranded cost recovery should be structured differently for different types of generation facilities. The Department recognizes that a different stranded cost recovery mechanism for nuclear units could raise equity issues

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39 In Section III, above, the Department proposes to require that electric company distribution affiliates meet customer electricity requirements through purchases from a power exchange.

40 For example, residual value may result from continued generation sales potential or the value of an existing site for repowering or replacement. Boston Edison Company, D.P.U. 88-28/88-48/89-100 (1989).

because Massachusetts electric companies have varying levels of commitment to different types of generating facilities. The Department solicits comments on these issues and poses the following questions:

1. Are there special considerations regarding nuclear units that require different or distinct treatment from other types of generation under our D.P.U. 95-30 principles on stranded costs?

2. Are there different market considerations for nuclear units than for units of other fuel types? For example, is nuclear power more or less marketable because of public perception, liability concerns, or operating costs, leading to different stranded cost recovery patterns?

3. If nuclear units continue to be subject to economic regulation, how could performance-based ratemaking be applied to them?[41]

4. How can nuclear units be exposed to competition without compromising their safe operation?

5. If special treatment is needed for nuclear stranded costs, please detail some possible recovery mechanisms.

4. Format for Filing of Stranded Costs

The Department has set forth, in the preceding sections, its objectives and policies with respect to the collection of stranded costs by electric companies. It is necessary that we also provide definitions and a standard format for the filing of stranded cost charge information by each electric company. The filings that have been made to date by Boston Edison Company, Eastern Edison Company, Massachusetts Electric Company, and Western Massachusetts Electric Company provide stranded cost calculations that differ substantially in terms of components, format, and calculation methods. Given the Department's aggressive schedule for the restructuring of the industry, and for the implementation of stranded cost recovery charges, common procedures for calculating and reporting stranded costs, and for Department review, are required at this time.

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41 The Department notes that cost recovery for the Pilgrim nuclear power plant currently is affected by a targeted performance mechanism.

The definitions, calculations, and formats are provided in the draft rules at 220 C.M.R. § 11.03. In that section, the Department divides a company's presentation into (1) that which is known and may be verified using publicly-available documents ("Embedded Costs"); (2) information on all company actions and occurrences that will reduce the level of embedded costs over time, which relies substantially on uncertain forecasts of load, sales, costs, and market prices ("Mitigation"); (3) the calculation of stranded costs using the information provided in (1) and (2) ("Stranded Costs"); (4) the allocation of, and mechanisms for collection of, stranded costs ("Mechanism for the Collection of Stranded Cost"); and (5) the procedures for Department review and reconciliation of stranded cost charges ("Department Review of Stranded Cost Presentations"). The Department believes that the mechanism for stranded cost calculations provided in the proposed rules will facilitate the review of company calculations, the setting of stranded cost charges, and subsequent stranded cost charge reconciliations.

The Department's definition of mitigation includes everything that reduces the level of embedded costs that companies would otherwise seek to collect from customers through the stranded cost charge, and explicitly identifies certain major categories (e.g., income from generation sales, renegotiation of power purchase contracts, voluntary writedowns, and asset sales). However, the Department stresses that this list is not exclusive. The Department expects companies to pursue all possible methods by which additional income and reduced expenses could minimize stranded costs. Actions that companies take, or should take, to maximize mitigation will be an important focus of stranded cost calculation and reconciliation proceedings. The Department requests comments on the company presentation of mitigation estimates and, in particular, on the questions that follow:

1. What is the full range of possible Mitigation actions beyond those specifically identified in the draft rules?

2. What incentives or disincentives do electric companies have to identify and accurately quantify the maximum extent of possible Mitigation actions?

3. Should electric companies be held accountable for Mitigation calculations? If so, how would this be accomplished, and for which categories of Mitigation?

Regarding the collection of stranded costs, 220 C.M.R. § 11.03(3)(a)(iv) identifies December 31, 2007 as the date on which company collection of stranded costs ends (with the exception of stranded costs related to nuclear decommissioning). This provides electric companies ten years from the expected start date for collection of stranded costs. The Department expects that, to the extent that companies reduce costs between now and December 31, 2007, stranded costs that would otherwise remain after the transition period could be recovered by December 31, 2007. Such an acceleration of stranded cost recovery is acceptable to the Department, provided that it is consistent with the Department's goal of reducing costs over time for consumers of electricity.

The mechanism for the collection of stranded costs in the draft rules reflects the Department's belief that stranded costs should be recovered in a manner that would be consistent with the existing methods of cost functionalization, classification, allocation, and design of rates for each rate class, which reflect the incurrence of costs. Moreover, since one of the Department's principles of restructuring is the development of an efficient industry structure that achieves full and fair competition in the generation market, the Department proposes that all stranded costs should be collected through a stranded cost charge only, leaving the supply price of electricity to be determined by the market. The design of the stranded cost charge might include both fixed and variable components to reflect cost incurrence. In this manner, the design would be consistent with the Department's rate structure goals. The Department solicits suggestions and illustrative tariff proposals from electric utilities and interested parties on the rate structure method to be used in the mechanism for the collection of stranded costs.

Finally, the Department includes in the draft rules a provision for the reconciliation of stranded cost charges. The Department believes that the level of uncertainty associated with projections critical to the mitigation calculation (e.g., market price and load growth) is far too great to not revisit such calculations. Further, the Department believes that this level of uncertainty will be greatest in the early years of the transition to a new market structure. Consequently, the Department proposes to set a periodic reconciliation schedule to reflect this dynamic, and a recovery bandwidth of the difference between projections and actual experience that broadens over time. In order to determine whether a reconciliation is warranted in a particular case, the Department will review company presentations of stranded cost calculations and determine the percentage difference between projections and actual experience at two, five and ten years subsequent to the date that the stranded cost charge is implemented. For example, one approach might be to use the following bandwidths: if the difference is less than 20 percent after two years, no reconciliation would be required, but a 20 percent or greater variation would warrant reconciliation to the edge of the bandwidth through an increase or decrease to the stranded cost charge for the subsequent rating period. If, after five years, the variation is 35 percent or greater, a similar reconciliation would be required. At the end of the ten-year recovery period, only if the variation is 50 percent or greater would a reconciliation be required. An alternative approach would be to use a narrower bandwidth to trigger reconciliation. The Department prefers a wider bandwidth to provide utilities with both the greatest opportunity to recover stranded costs and with the greatest incentive to mitigate stranded costs. Such a bandwidth would reflect the responsibility of utilities to increase the efficiency of their operations and to work to mitigate stranded costs, and would allocate reward and risk commensurate with that responsibility. It would also help other market participants and customers adjust their expectations and adapt to the greater uncertainties of a competitive marketplace. The Department requests comment on the timing and proposed bandwidths for stranded cost reconciliations.

5. Property Taxes

The restructuring of the electric industry may impact utilities and municipalities with reference to local property taxes in two ways. First, utility companies have raised concerns that, should a plant decrease in value as a result of its inability to compete in the market, property taxes might not decrease at the same rate. Property taxes thus would represent a cost that would exist independent of the operation of the utility's plant for a period of time, and which the utilities argue they should be provided a reasonable opportunity to recover. Conversely, municipalities have raised concerns that, should a plant decrease in value as a result of its inability to compete in the market, property tax revenues to the municipality would likewise decrease.

The Department views the transitional period of restructuring as a transitional period for municipalities as well. The Department proposes that, when stranded costs in excess of market value for a plant are recovered from customers, then property taxes based on the combined market value and the stranded cost collection should be paid in property taxes to municipalities throughout this period.[42]

B. Energy Efficiency Services

In a fully competitive generation environment, energy efficiency services should be provided by the market. The Department's expectation is that the new market environment, in which real-time prices will be transparently available to all producers and consumers of energy and energy management services, is likely to spur the development of a market for newly cost-effective energy management technologies that reduce consumption during expensive peak periods and/or shift peak demands to less expensive, off-peak periods. Any sector of the energy efficiency services market which is sufficiently competitive will not require regulatory intervention, and as new sectors of this market become competitive, regulatory intervention should be curtailed and eventually eliminated. However, there are two reasons to continue some level of regulation of these services, even in a market environment.

42 Senator Murray has recently filed a bill in the Massachusetts Senate to compensate municipalities for any loss in property tax revenue which may result from a devaluation of electric generation facilities due to the restructuring of the electric industry. The bill would offset any reduction of property tax revenues paid to a city or town for the period of time the electric company is allowed to collect stranded costs. While not taking a position on the details of this bill, the Department believes that the legislature is an appropriate forum to decide this issue.

First, some of the market barriers that currently exist for these services are likely to continue and may prevent these services from competing, e.g., insufficient information about energy efficiency, lack of financing options, the inability of low-income customers to purchase energy efficiency measures,[43] and the differing motivations of landlords and tenants. The Department's primary goal is to eliminate market imperfections where possible, and to mandate utility-sponsored energy efficiency programs only where market failures continue to exist. Continued regulatory support of utility-sponsored energy efficiency programs is one method of mitigating the effect of market failures.

Second, it is in the public interest for the Department to continue to support and encourage the development of the energy efficiency industry in Massachusetts. Energy efficiency provides the opportunity for consumers to lower their electric bills (and, for commercial and industrial customers, to remain competitive), while enhancing customer choice, and lowering the environmental impact of providing electric service.[44] In addition, while furthering the goals stated in D.P.U. 95-30, energy efficiency programs further the goal of increased energy efficiency mandated in the Massachusetts Energy Plan and the National Energy Policy Act of 1992.

In D.P.U. 95-30, the Department stated that utility-sponsored energy efficiency programs should remain in effect during the transition so that the fledgling energy efficiency

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[43] The inability of low-income customers to purchase energy efficiency services, and the continued inefficiencies of low-income housing stock, are market imperfections that may well continue for the foreseeable future. Provision of low-income energy efficiency services, coordinated through Weatherization Assistance Program (WAP) agencies, is one way to address these market failures. The Department invites comments on whether energy efficiency programs or low-income discounts are a more efficient way to assist low-income customers.

[44] In the past, the Department has also mandated that utilities consider demand-side resources on an equal footing with supply-side resources when making procurement decisions. See 220 C.M.R. §§ 10.00 et seq. As we proceed with restructuring, the Department anticipates that energy efficiency may continue to be a less costly alternative to distribution system upgrades. Performance-based ratemaking should provide the incentive for distribution companies to choose the least-cost alternatives for distribution system expansion activities.

service industry may have a meaningful opportunity to compete with other electric services in the future. Id. at 30. In a recent Order, the Department stated that the transition from electric company-sponsored DSM programs to energy efficiency services that compete effectively in an open market will best be accomplished through a gradual shift rather than through an abrupt cessation of traditional electric company-sponsored DSM. Western Massachusetts Electric Company, D.P.U. 96-8-CC at 7 (1996). The Department's proposed rules would implement that gradual shift, and would require all investor-owned electric companies to file their plans for energy efficiency during the transition.[45]

The Department expects that, during the transition to a competitive marketplace, the nature of utility-sponsored energy efficiency initiatives will evolve. The Department has recently endorsed market-driven energy efficiency programs[46] that are designed to take advantage of market opportunities for more efficient use of energy at a time when it is most practical and inexpensive to do so, such as during new construction, renovation, equipment replacement, or at the time of purchase of new equipment. The Department proposes that each investor-owned electric company file a plan that includes a movement away from traditional retrofit programs towards market-driven programs over a five-year period.

Market transformation efforts are designed to create long-term changes that reap continuous energy efficiency savings at low cost. The Department proposes that transition

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45 Participation by regulated utilities in a niche role may continue to provide value after the transition has occurred. Utilities continue to be in an unique position to provide certain services in the energy efficiency market. The utilities' long-term role may include supporting market transformation activities on a regional or national level; providing technical assistance; providing technical and customer information; using existing relationships with retail customers to disseminate energy efficiency information to customers and customer/marketing information to the market; providing referrals to and coordinating with sources of private financing; coordinating with energy efficiency experts to identify potential energy savings; and supporting research and development of energy efficiency technologies in the private sector. The Department will not define this role at the present time.

46 Western Massachusetts Electric Company, D.P.U. 96-8-CC at 7 (1996); Boston Gas Company, D.P.U. 94-109 (Phase II) at 6, Interim Order on Gas Demand-Side Management (1996).

programs include participation in market transformation efforts sponsored by private industry, regulatory agencies, or other entities that aim to develop new energy efficiency technologies and to upgrade building codes and standards. In addition, the Department proposes that transition programs include a consumer information component that would educate consumers about the benefits of energy efficiency services and increase customer demand for new technologies to control energy use. Increase in demand should encourage private energy service companies to provide more services, thereby providing customers with more choice and opportunities.

Concomitant with the evolution of the nature of utility-sponsored energy efficiency programs should be a ramping-down of budget levels for these programs over five years. Proposals filed by electric companies should include budget levels that reflect the changing nature of utility energy efficiency programs, and that are designed to recover the costs of only those energy efficiency services which cannot be provided by the market.[47]

C. Renewable Energy Resources

Renewable energy resources ("renewables") can assist in achieving the environmental goals of the electric industry since they generally represent a source of electricity with low environmental impact. In addition, they include emerging technologies that could prove valuable in providing electricity in a restructured industry, by increasing the diversity of the resource base and offering more options for customers. Thus the Department is interested in ensuring that renewables have a meaningful opportunity to compete in the emerging market for electricity and energy services.

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[47] The Department expects that, as electric companies make the transition from traditional DSM programs (where savings could be measured with a degree of precision that allowed the calculation of lost base revenues ("LBR") and incentives) to market transformation efforts (where savings are difficult to measure or to attribute to a single entity's performance), companies will propose cost recovery for energy efficiency that includes LBR and/or incentives for only those portions of the programs that continue to exhibit characteristics of "traditional" utility company DSM programs.

The Department favors market-based approaches that remove barriers to competition and offer incentives for market participants to explore the viability of renewables rather than approaches that require regulatory intervention to maintain a particular level of renewables in the market. Under the Department's proposed rules, customers who choose to purchase energy from renewable sources will have three options.

First, some renewables will be available at a cost only slightly above the market price of electricity. Retail customers who are willing to pay a small premium should have the option of purchasing from a renewable energy source or from a portfolio that includes renewable resources, thereby assuring the inclusion of these resources in the overall system dispatch. The funding mechanism proposed by the Department below should encourage private renewable energy producers to offer these resources to retail customers.

Second, renewables that cost more than the premium customers are willing to pay may be worth encouraging because, with greater market penetration and experience, they have the potential to become competitive. These resources could be introduced to the market via a renewables fund that would be used to offset a portion of the difference between the price of power from the renewable energy source and the price that customers are willing to pay for power from a renewable resource. The Department believes that customers who choose to purchase this power should still pay a premium to account for a portion of the difference between the market price for electricity and the higher price for these renewables. The fund could be collected through a low (e.g., 1 mill per KWH), non-bypassable charge on distribution services, and could be distributed to renewable resource providers based on criteria to be determined once the fund is established. The Department proposes that such a fund be used to foster competition in resources that cost only slightly more than the premium customers are willing to pay to purchase renewables.

Third, the Department notes that customers have the option of generating power to meet some or all of their energy needs from a renewable energy source located on their property.[48] Under current rules, the electric company must pay customers for the positive difference between kilowatthours delivered and consumed, a practice known as net billing. 220 C.M.R. § 8.04(2)(c). The Department proposes that the distribution company would continue to be required to purchase from the customer any power generated by the customer's on-site renewable energy source but not used by the customer.

The Department invites comments and/or responses to the following questions:

1. The Department requests comments on the appropriateness and effectiveness of a renewables fund mechanism, including the level of the premium customers may be willing to pay to purchase electricity from renewable resources, the level of funding (on a per/KWH basis) above the basic renewables premium that would make other renewables competitive, and the level of the charge. The Department also seeks comments on how the fund should be administered.
2. The Department seeks comments on how the power buy-back might be implemented by the Department, addressing whether the practice proposed herein would conform to the Department's regulations that implement the Public Utility Regulatory Policies Act (220 C.M.R. 8.00 et seq.).
3. For the purposes of net billing, what price should the distribution company be required to pay the customer for power generated by a renewable energy resource, taking into account the value of the generation to the distribution company: the market price of generation or the customer's total retail prices per kilowatthour?

VI. PERFORMANCE-BASED REGULATION FOR DEPARTMENT-REGULATED ELECTRIC COMPANIES

A. Introduction

In Incentive Regulation, D.P.U. 94-158 (1995), the Department established the criteria by which performance-based regulation ("PBR") proposals for electric and gas companies would be evaluated. These criteria require that PBR proposals:

(1) comply with Department regulations, unless accompanied by a request for a specific waiver;

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48 The Commonwealth of Massachusetts currently recognizes the importance of renewable energy sources, offering a number of tax incentives to commercial and residential utility customers who operate renewable energy sources at their facilities or residences. These tax incentives apply to income, property, excise and sales taxes, and are designed to promote the development and use of renewables by residential and commercial entities in the state.

> (2) be designed to serve as a vehicle to a more competitive environment and to improve the provision of monopoly services. Incentive proposals should avoid the cross-subsidization of competitive services by revenues derived from the provision of monopoly services;
>
> (3) not result in reductions in safety, service reliability or existing standards of customer service;
>
> (4) not focus excessively on cost recovery issues. If a proposal addresses a specific cost recovery issue, its proponent must demonstrate that these costs are exogenous to the company's operation;
>
> (5) focus on comprehensive results. In general, broad-based proposals should satisfy this criterion more effectively than narrowly-targeted proposals;
>
> (6) be designed to achieve specific, measurable results. Proposals should identify, where appropriate, measurable performance indicators and targets that are not unduly subject to miscalculation or manipulation; and
>
> (7) provide a more efficient regulatory approach, thus reducing regulatory and administrative costs. Proposals should present a timetable for program implementation and specify milestones and a program tracking and evaluation method.

Id. at 58-64.

There was general agreement among the commenters in D.P.U. 94-158, that PBR plans should be designed on a case-by-case basis, to account for important differences among utility companies and their service territories. The Department did not prescribe or endorse a specific mechanism in that Order, stating that, "[a]t least for the present, the Department agrees with these recommendations [of the commenters]. The Department will evaluate and review incentive proposals on a utility-specific basis, consistent with the general principles and guidelines stated in this Order." Id. at 19, 57, 62.

Since the issuance of D.P.U. 94-158, several companies have filed PBR plans for Department review. The majority of these plans called for the implementation of a price cap mechanism. In NYNEX, D.P.U. 94-50 (1995), the Department approved a price cap plan, stating that a well-designed price cap is preferable to rate-of-return regulation for NYNEX. Id. at 107-112. The Department stated that, as with the results produced by competitive markets, a well-designed price cap would allow a regulated monopoly the opportunity to increase its earnings through above-average gains in productivity. Id. at 110. On

February 16, 1996, WMECo, BECo and EECo filed price cap proposals as part of their plans for the restructuring of the electric industry.

Of those companies that have submitted PBR proposals for Department review, only MECo has proposed a non-price cap PBR plan. In Massachusetts Electric Company, D.P.U. 95-40-A (1995), the Department rejected MECo's rate-benchmarking proposal, stating that MECo's proposal was not consistent with the criteria established in D.P.U. 94-158. Id. at 16-22. MECo's most recent PBR proposal, filed on February 16, 1996 with its restructuring filing, called for the implementation of a cost-benchmarking mechanism.

The Department suggests that there are advantages to be gained by having all electric companies implement the same PBR mechanism. In particular, it may be advantageous for all companies to implement price cap plans. The Department believes that such uniformity among companies (1) is equitable because a company's earnings would be based on its ability to achieve efficiencies and not on the selection of a particular PBR mechanism; and (2) would promote administrative efficiency by simplifying the Department's task of reviewing and evaluating these plans. Because price cap plans are intended to reflect pricing trends produced by a competitive market, the Department believes that such plans are uniquely suited to satisfy the evaluation criteria set forth in D.P.U. 94-158. Therefore, consistent with the guidelines included below and in the draft rules, the Department proposes that all Massachusetts electric companies implement price cap plans.

B. Price Cap Plan

A price cap plan typically works in the following manner. First, rates are set according to traditional cost-of-service regulation. Thereafter, for the term of the price cap plan, the annual increase in rates is limited by a price cap index ("PCI") that is calculated according to the formula:

$$PCI_{new} = PCI_{current} * (1 + P - X \pm Z)$$

where P is a factor that reflects inflation;

X is a factor that includes components that reflect productivity gains, a "customer dividend," accumulated inefficiencies[49] and an input price differential; and

Z is a factor that reflects costs associated with exogenous factors.

There are three commonly-used price cap plans which differ according to the indices selected for measuring changes in price and productivity:

(1) A market-style price cap uses an industry-specific output price index as the P factor. This type of price cap uses a productivity factor equal to zero because it assumes that industry output price trends will automatically reflect the industry's productivity gains.

(2) A railroad-style price cap uses an industry-specific input price index as the P factor. This type of price cap uses a productivity factor that reflects the expected productivity gains of the industry.

(3) A telecommunications-style price cap uses an economy-wide output price index as the P factor. This type of price cap uses a productivity factor that reflects the difference between economy-wide productivity gains and industry-specific productivity gains.

As stated in D.P.U. 94-158, a PBR plan should not result in reductions in safety, service reliability or existing standards of customer service. The Department considers it essential that, in addition to the factors described above, a price cap plan include a performance component that establishes minimum standards of safety, service reliability, and customer service that a company would be required to maintain. Because these standards would represent minimum performance levels, the Department proposes that this performance component of the price cap be designed so that a company would not be financially rewarded

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[49] Accumulated inefficiencies refers to a component of the productivity offset that reflects the inefficiencies, if any, that have accumulated over time in the rates of electric companies under cost-of-service regulation.

for maintaining or exceeding these standards but rather would be penalized for not meeting the standards.

Consistent with the Department's objective of having all Massachusetts electric companies implement the same type of PBR mechanism, the Department sees benefits in specifying, to the extent reasonable, a price cap approach (and thus, identifying specific measures of price changes and productivity) that would be implemented by all electric companies. Similarly, the Department is interested in developing a consistent definition of exogenous factors and percentage of revenues floor for each exogenous cost, and a list of performance standards that would be included in all companies' price cap plans. The Department will not specify, in this statement and accompanying proposed rules, the specific price cap approach to be used by each company nor the exogenous factors and performance standards to be included in the price cap plans. Instead, the Department proposes that these factors be determined during the adjudication of the first price cap proposal submitted by an electric company subsequent to the effective date of the final rules in this proceeding.[50] The Department expects that findings made during this first adjudication would apply to the "first round" of price caps (i.e., the first full term of each company's price cap). The Department would evaluate the performance of the first round of price caps in determining future ratemaking approaches.

Consistent with the guidelines stated above, the Department proposes that all Massachusetts electric companies submit price cap proposals for Department review concurrent with the filing of their first general rate case subsequent to the effective date of the final rules in this proceeding. Such a filing is not required for the implementation of revenue-neutral, unbundled rates on January 1, 1997.

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[50] The Department expects that all electric companies would participate in at least this phase of the first adjudication. Companies would be allowed the opportunity to present evidence demonstrating, among other things, that certain factors should not be applied uniformly to all companies.

VII. THE DEPARTMENT'S SOLICITATION OF COMMENTS

The Department solicits general comments on the proposed rules, and on the specific issues raised by the Department in this statement. The proposed rules are attached to this Order as Attachment A. A copy of the proposed rules may be inspected at the Department's offices, 100 Cambridge Street, 12th Floor, Boston, Massachusetts. Interested persons may file comments, alternative rules, suggested hearing questions and requests to present oral testimony at hearings, for the Department's consideration in adopting final rules, with Mary L. Cottrell, Secretary, Department of Public Utilities, 100 Cambridge Street, 12th Floor, Boston, Massachusetts 02202, on or before May 24, 1996. Pursuant to G.L. c. 30A, § 2, the Department plans to hold public hearings three days a week from June 10, 1996 through July 19, 1996 (there will be no hearings the week of July 1, 1996 through July 5, 1996) at the Department's offices to hear public comment on the proposed rules. In our March 15, 1996 procedural ruling, the Department included evening public hearings in May to receive public comment on the May 1 statement and draft rules. Given the complexity of the issues and the length of the May 1 documents, the Department revises the dates for evening public evenings to July. This will allow the public additional time to review the May 1 proposals as well as the responses to the May 1 proposals, and to attend the hearings in June and July. This additional time will also permit the Consumer Education Advisory Task Force[51] to coordinate with the Department and utilities on consumer notice and education. Consumers will be notified of the dates of the July evening public hearings through their utilities and through newspaper notice. After hearings, the Department will accept reply comments and/or recommended changes to the proposed rules, filed on or before August 2, 1996. The

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[51] The Consumer Education Advisory Task Force ("Task Force") was created by the Department in its March 15, 1996 Procedural Ruling in order to ensure public education and opportunities for public input throughout the restructuring process. The Task Force is coordinated by Claudine Langlois, Director of the Consumer Division of the Department. Anyone interested in participating in the Task Force should contact Ms. Langlois at (617) 727-3531/3532.

Department anticipates that final regulations will be filed with the Secretary of State on September 20, 1996, for publication and effect on October 4, 1996.

By Order of the Department,

John B. Howe, Chairman

Mary Clark Webster, Commissioner

Janet Gail Besser, Commissioner

ATTACHMENT A

220 CMR 11.00: PROPOSED RULES GOVERNING THE RESTRUCTURING OF THE ELECTRIC INDUSTRY IN THE COMMONWEALTH OF MASSACHUSETTS

Section

11.01: Purpose and Scope

(1) Purpose. 220 CMR 11.00 establishes the rules that will govern the restructuring of the electric industry and will apply thereafter to the restructured electric industry in the Commonwealth of Massachusetts. Their purpose is to provide a framework for an efficient industry structure and regulatory oversight that will minimize long-term costs to consumers while maintaining the safety and reliability of electric services with minimum impact on the environment.

(2) Scope. 220 CMR 11.00 applies to the distribution companies, power marketers and brokers, and generation suppliers, as appropriate, that will participate in the electric industry in Massachusetts following the effective date of these rules, including the following investor-owned electric companies and their successors or assigns:

a. Boston Edison Company
b. Cambridge Electric Light Company
c. Commonwealth Electric Company
d. Eastern Edison Company
e. Fitchburg Gas and Electric Light Company
f. Massachusetts Electric Company
g. Nantucket Electric Company
h. Western Massachusetts Electric Company

11.02: General Definitions The terms set forth below shall be defined as follows, unless the context otherwise requires.

Ancillary Services are those functions that support Generation, Transmission, and Distribution and shall include the following services: (1) reactive power/voltage control; (2) loss compensation; (3) scheduling and dispatch; (4) load following; (5) system protection service; and (6) energy imbalance service.

Cost-of-Service Regulation ("COSR") shall mean the traditional regulatory model in which rates are based upon prudently incurred costs and a reasonable return on an electric company's investment.

Department shall mean the Department of Public Utilities.

Distribution shall mean the delivery of power from the transmission system to an end-use customer within Massachusetts. Distribution service is typically equal to or greater than 110 volts and less than 69,000 volts and is under the jurisdiction of the Department. See also, FERC definition of distribution in Order No. 888.

Distribution Company shall mean an Electric Company, as defined below, or a company organized under the laws of the Commonwealth of Massachusetts for the purpose of distributing electricity within the Commonwealth.

Distribution Service shall mean the delivery of electricity to the customer by the Distribution Company from points on the transmission system or from a generating plant operating at distribution voltage.

Electric Company shall mean an investor-owned electric utility that provides Generation, Transmission, and Distribution Services. This definition applies to those electric companies listed in Section 220 CMR 11.01(2).

Electric Service shall mean the provision of Generation, Transmission, Distribution, and Ancillary Services.

FERC shall mean the Federal Energy Regulatory Commission.

General Access Charge shall mean the charge that provides the mechanism by which a Distribution Company will recover its costs for public policy goals, including discounts for Low-income Customers and costs for Energy Efficiency and Renewables.

Generation shall mean the act or process of transforming other forms of energy into electric energy, or the amount of electric energy so produced.

Generation Service shall mean the provision of Generation to a customer.

Low-income Customer shall mean any residential customer who (1) meets the eligibility criteria for service under a Distribution Company's Low-income Tariff, and (2) takes service under such a tariff.

Power Exchange shall mean an entity through which real-time trades of electricity between buyers and sellers are made, and through which spot prices are established.

Stranded Cost Access Charge shall mean the charge that provides the mechanism for recovery of a utility's Stranded Costs, as defined in 220 CMR 11.03(2).

Supplier shall mean any supplier of generation to retail customers, including load aggregators, power marketers, and brokers.

Transition Period shall mean the period between the effective date of these rules and the realization of a fully competitive generation market with full retail choice. The Department envisions that the transition period may last up to ten years for purposes of stranded cost recovery.

Transmission shall mean the delivery of power (at a level typically equal to or greater than 69,000 volts) from generating units across interconnected high voltage facilities to points where the power enters the distribution system. Transmission is under the jurisdiction of the FERC. See also, FERC Order No. 888.

Transmission Service shall mean the provision of Transmission to a customer.

11.03: Stranded Cost Recovery

(1) Purpose and Scope.

(a) Purpose. The purpose of this Section is (1) to establish the information that shall be filed by an Electric Company for Department review of stranded cost calculations; (2) to establish the procedures by which an Electric Company shall calculate net, non-mitigable stranded costs; (3) to set forth the procedure for Department review of stranded cost calculations; and (4) to outline the mechanisms by which stranded costs may be collected over time.

(b) Scope. Section 11.03 applies to the investor-owned electric companies listed in 220 CMR Section 11.01(2).

(2) Specific Definitions.

Embedded Costs shall mean the cost of existing assets and obligations incurred by an Electric Company prior to August 16, 1995, pursuant to the provision of electric service, including (1) the amount of the book cost directly related to existing generating facilities that are wholly or partly owned by the company, (2) the minimum financial obligation under existing long-term power purchase contracts, (3) the amount of the book costs associated with regulatory assets related to generation, and (4) the amount of costs that will be required to decommission nuclear generating facilities.

Mitigation shall mean all actions or occurrences that reduce an Electric Company's level of embedded costs over time, including both matters within the company's control (e.g., asset sales) and those resulting from matters not wholly within the company's control (e.g., load growth). Mitigation includes, but is not limited to, (1) sales of capacity, energy, and ancillary services from generating facilities that are wholly or partly owned by the company; (2) sales of capacity, energy, and ancillary services from generating facilities with which the company has a power purchase agreement; (3) adjustments to the company's minimum obligations under power purchase agreements that decrease such obligations, and that may be obtained through contract buy-out or renegotiation; and (4) sales and voluntary writedowns of company assets.

Stranded Costs shall mean the Embedded Costs that remain after accounting for maximum possible Mitigation of such costs. Stranded Costs shall be calculated as set forth in 220 CMR 11.03(3)(a)(iv).

(3) The Calculation of, and Mechanisms for the Recovery of, Stranded Costs by Investor-Owned Electric Companies.

(a) Documents to be Filed. Each Electric Company's filing shall contain the following documents and information, which shall be submitted in paper and electronic format. Text shall be submitted on a diskette in WordPerfect for Windows 5.1 format and charts, graphs, and tables shall be submitted on a diskette in Excel 5.0 format.

(i) Executive Summary. The Executive Summary shall be a non-technical text and tables that present, in summary format, the information contained in the following documents.

(ii) Embedded Costs Summary.

1. The company shall present Embedded Costs for the following four categories: (a) the amount of the book costs directly related to existing generating facilities that are wholly or partly owned by the company; (b) the minimum financial obligation under existing long-term power purchase contracts; (c) the amount of the book costs associated with regulatory assets; and (d) the amount of costs that will be required to decommission nuclear generating facilities.

2. The company shall present the book costs of owned generating facilities (a) by plant, (b) aggregated by fuel type, and (c) in total.

3. The company shall present minimum power purchase contract obligations (a) by generating facility or contract, (b) aggregated by fuel type, and (c) in total. For each generating facility or contract, the company shall demonstrate how the minimum obligation is calculated, and shall summarize all contract provisions that could allow for contract termination or renegotiation.

4. The company shall indicate what portion of nuclear decommissioning cost estimates derives from generating facility operation after August 16, 1995.

5. The company's presentation for each category of Embedded Costs shall include a presentation of such information as it was reported in the company's FERC Form 1 filings beginning with the year 1994.

6. All adjustments in the company's presentation of Embedded Costs from the values presented in the most recent FERC Form 1 filing shall be accompanied by a description of the reasons for, and method of calculating, such adjustments.

(iii) Mitigation Summary.

1. The company shall present estimates of Mitigation of Embedded Costs for at least the following four categories: (a) net income (revenue less operating expenses) from sales of capacity, energy, and ancillary services from generating facilities that are wholly or partly owned by the company (by facility and in total); (b) net income from sales of capacity, energy, and ancillary services from generating facilities with which the company has power purchase agreements (by agreement and in total); (c) adjustments to the company's minimum obligations under power purchase agreements that decrease such obligations,

such as may be obtained through contract buy-out or renegotiation; and (d) sales and voluntary writedowns of company assets. The company shall include other categories for the Mitigation of Embedded Costs as appropriate. The company shall present a total of all Mitigation estimates provided.

2. The company shall present estimates of Mitigation of Embedded Costs both on a present-value basis and on an annual basis over the period for which Mitigation estimates are presented. The company shall state its assumptions and provide details of its calculation of present value.

3. The company shall provide a summary of, and the basis for, all projected market prices used in Mitigation estimates.

4. The company shall provide the forecast of future load that affects Mitigation estimates. The company shall describe the method used to develop the load forecast.

5. The company shall estimate net income from sales of capacity, energy, and ancillary services from wholly or partly owned generating facilities for the expected life of the facility. In support of this estimate, the company shall provide projections of generating facility annual output and life expectancy. The company shall provide support for any projections of generating facility operation and maintenance costs used in this estimate. The company shall include all income from such sales between January 1, 1998 and December 31, 2007 in its Mitigation projection.

6. The company shall estimate net income from sales of capacity, energy, and ancillary services from generation facilities with which the company has power purchase agreements for the term of the company's purchase under each agreement. In support of this estimate, the company shall provide projections of generating facility annual output. The company shall include all income from such sales between January 1, 1998 and December 31, 2007 in its Mitigation projection.

7. In support of its summary of opportunities to decrease its total costs or obligations under existing power purchase agreements through contract buy-out or renegotiation, the company shall provide a description of all such efforts that have been undertaken or are underway at the time of filing.

8. In support of its opportunities for and possible timing of expected sales of company assets, the company shall explain how such sales would affect the Stranded Cost calculation.

9. The company shall be required to undertake good faith efforts to maximize net revenues from its own generating units, contract purchases, and other optional sources, and shall provide evidence to the Department of all such efforts.

(iv) <u>Stranded Costs Summary</u>.

1. The company shall calculate Stranded Costs by subtracting Mitigation projections from Embedded Costs.

2. *[In the event that the Department orders a mechanism to provide companies with incentives for the sale of generation assets, or the Department approves an agreement among parties*

that provides incentives for the sale of generation assets, the company shall adjust its calculation of Stranded Costs in accordance with application of this incentive. Please refer to Section V.A of the explanatory statement for a discussion of incentive mechanism options to be considered for inclusion here].

3. The company shall present a calculation of Stranded Costs on a present value basis in total for the company. The company shall also separate the Stranded Costs into those attributable to (a) specific generating facilities, (b) specific contracts, and (c) nuclear decommissioning. The company shall state its assumptions and provide details of its calculation of present value.

4. In addition to the present-value calculation provided for in the previous section, for all Stranded Costs other than those attributable to nuclear decommissioning, the company shall present estimates of Stranded Costs in terms of (a) total dollars, and (b) cents per kilowatthour, for each year between and including 1998 and 2007. The company shall summarize the method and assumptions used in the cent-per-kilowatthour calculation.

5. For nuclear decommissioning costs, the company shall present estimates of Stranded Costs in terms of (a) total dollars, and (b) cents per kilowatthour, for each year until the current operating license expiration date of the nuclear facilities. The company shall summarize the method and assumptions used in the cent-per-kilowatthour calculation.

(v) Summary of the Mechanism for the Collection of Stranded Costs.

1. The company shall recover the level of Stranded Costs approved by the Department through the Stranded Cost Access Charge.

2. The company shall recover Stranded Costs in a manner that is consistent with existing methods of cost functionalization, classification, allocation, and rate design for each rate class.

3. The company shall collect stranded costs through a charge that has fixed and variable components, applied to the distribution portion of customers' bills.

4. The company's collection of Stranded Costs shall end on December 31, 2007, for all categories of Embedded Costs with the exception of nuclear decommissioning costs. Nuclear decommissioning costs shall be collected each year until the operating license expiration date in effect as of August 16, 1995.

(4) Department Review of Stranded Costs Presentations.

1. The Department will review company presentations of stranded cost calculations and mechanisms, and will approve or require adjustments to such calculations within 180 days of a company's filing.

2. The Department may require compliance filings by a company to implement any changes ordered by the Department upon review of the company's presentation. Compliance filings shall be due within 30 days of the Department's order.

3. At intervals two, five, and ten years subsequent to the date upon which the Stranded Cost Access Charge is implemented, each company shall file a presentation of the differences between projections and actual experience and, if necessary, present an appropriate adjustment to the Stranded Cost Access Charge. If, at these intervals, the difference between projections and actual experience falls outside of specified bandwidths, the Department will adjust a company's Stranded Cost Access Charge to bring the company's recovery back to the edge of the bandwidth. The bandwidth for each interval is as follows: [year 2, ±20%; year 5, ±35%; year 10 or January 1, 2008, whichever is sooner, ±50%. See Discussion in Explanatory Statement at Section V.A.4].

11.04: Performance-based Regulation

(1) Purpose and Scope.

(a) Purpose. This Section establishes the rules for the design and implementation of a Price Cap mechanism, a form of Performance-based Regulation.

(b) Scope. This Section applies to the Department-regulated functions of Distribution Companies.

(2) Specific Definitions.

Accumulated Inefficiencies shall mean a component of the Productivity Offset in the Price Cap Formula that reflects any inefficiencies that have accumulated over time in the rates of Electric Companies under Cost-of-Service Regulation.

Customer Dividend shall mean a component of the productivity offset that reflects the increase over historical productivity of the Distribution Company in the electric industry that can be expected when the Distribution Companies in the industry are regulated under price cap regulation.

Exogenous Costs shall mean positive or negative costs reflecting changes beyond the Distribution Company's control and not captured in the other components of the Price Cap Formula. These may include, but not be limited to, costs resulting from storms, changes in tax laws, accounting changes, and regulatory, judicial or legislative changes that uniquely affect the electric industry. Exogenous Costs are represented in the Price Cap Formula as the "Z factor."

Inflation Factor shall mean a measure of one of the following: changes in electric industry output prices; changes in electric industry input prices; or changes in economy-wide output prices. The Inflation Factor is represented in the Price Cap Formula as the "P factor."

Input Price Differential shall mean a component of the Productivity Offset that reflects any difference in the change in input prices between the United States economy and the electric industry over a relevant period of time.

Performance-based Regulation ("PBR") shall mean incentive rate mechanisms that replace COSR.

Price Cap shall mean a type of PBR where an initial price or set of prices is established, and thereafter the level of allowed revenues adjusts automatically as a function of inflation less an allowance for productivity improvement, while incorporating any positive or negative Exogenous Costs.

Productivity Offset shall mean a component of the Price Cap Formula that accounts for the expected improvement in productivity consistent with that of the average firm in the electric industry under price cap regulation, and may also account for an input price differential, a Customer Dividend, and Accumulated Inefficiencies. The Productivity Offset is represented in the price cap formula as the "X factor."

Service Quality Index ("SQI") shall mean an index of non-price standards that tracks a Distribution Company's performance with respect to Distribution level reliability, safety and customer service.

System Average Interruption Duration Index ("SAIDI") shall mean a measure of system reliability, calculated as the ratio of customer outage hours over the course of a year for an entire distribution system, divided by the total number of customers served by that system.

(3) Initial Price Cap Filing Requirements.

(a) Initial Filing Schedule. Each Distribution Company shall file a Price Cap Plan with its first general rate case filing after the effective date of these rules.

(b) Document Filing Requirements. Each Distribution Company shall file a Price Cap Plan consistent with these rules. These plans shall include prefiled testimony and supporting documentation.

(c) Department Review. In the first adjudication of a Distribution Company's price cap plan after the effective date of these rules, the Department will determine the following price and non-price factors that will be applied to the price cap plans of all the Distribution Companies: the P factor; the X factor; the percentage-of-revenues floor for each exogenous cost; SQI measures; SQI penalty provisions; and the term of the plan. See 220 CMR 11.04(5) and 11.04(6).

(4) Initial Rates. For purposes of determining the appropriate initial rates to which the Price Cap Formula should be applied, Distribution Companies shall submit information consistent with Department procedures under COSR. The filings shall include cost-of-service studies, marginal cost studies, tariffs, prefiled testimony, and supporting documentation.

(5) Price Cap Regulation.

(a) Price Cap Formula. The annual change in rates to each rate class shall be limited by a price cap index ("PCI") calculated according to the following formula:

$$PCI_{new} = PCI_{current} * (1 + P - X \pm Z)$$

Where:

P represents inflation
X represents the productivity offset
Z represents exogenous cost changes

The PCI will initially be set at 1.0 and will be adjusted annually. The PCI shall apply to the rates of the Department-regulated functions of the Distribution Company. The PCI shall not apply to either the Stranded Cost Access Charge or the General Access Charge.

1. Inflation Factor. The P factor as determined by the Department shall reflect an inflation index.

2. Productivity Offset. The anticipated change in the X factor as determined by the Department shall reflect either the productivity of the electric industry or the difference between the productivity of the United States economy and the electric industry.

3. Exogenous Cost Factors. Any proposal that seeks recovery of Exogenous Costs must demonstrate that the Exogenous Costs warrant separate and specific rate treatment; i.e., that these costs are beyond the Distribution Company's control and are not captured in the other components of the Price Cap Formula. The Z factor as determined by the Department will be set on a company-specific basis, but must be derived from events that are outside the control of the Distribution Company that have directly affected its costs and/or performance. During the annual review of the Price Cap, if a dispute arises as to the propriety of an Exogenous Cost, the proponent of the Exogenous Cost adjustment will bear the burden of proof. In addition, the proponent of the Exogenous Cost adjustment bears the burden of demonstrating that the Exogenous Cost has not been reflected in the P factor. See 220 CMR 11.04(7).

(b) Calculation of non-price component of plan. To ensure that each Distribution Company maintains a high level of service quality, each Price Cap Plan shall include measures of performance of service quality. The SQI, as determined by the Department, shall be measured against target levels and standard levels, as predetermined by the Department. Failure to meet established SQI thresholds will result in a penalty (i.e., an increase in the productivity offset). The SQI shall include measures of reliability, safety, and customer service. Reliability measures may be calculated as a function of SAIDI, the frequency and duration of outages, and the performance of the set of least reliable distribution circuits. Safety measures may be calculated as a function of lost time accident frequency rate, and recordable injury rate. Customer service measures may be calculated as a function of surveys, call center performance, and response time for customer-related appointments.

(6) Term of plan. Price Cap Plans shall be of no less than five years in duration and will be evaluated by the Department at the end of the term in order to determine future ratemaking approaches.

(7) Annual Filings. The Price Cap Formula will be applied, annually, to establish new rates for each rate class. Companies must make filings to support these rate adjustments, which the Department will investigate for compliance with the Price Cap rules.

(8) Earnings Regulation. During the term of the Price Cap Plan, Distribution Companies shall not be subject to COSR and will be exempt from challenges to, or review of, their earnings based on principles of COSR.

11.05: Universal and Basic Service

(1) Purpose and Scope.

(a) Purpose. These rules set forth the terms and means by which Universal Service for residential customers, and the terms and means by which Basic Service for residential and non-residential customers, will be offered in the restructured electric industry. This Section establishes rules of procedure that will allow electric distribution companies to (1) continue to distribute electricity to residential and non-residential customers in their territories, (2) bill customers for the Generation, Transmission, and Distribution Service that they provide, (3) bill for Generation Service provided to customers in their service territory by a Supplier, and (4) terminate service to customers for non-payment of bills.

(b) Scope. These rules and the provisions set forth at 220 CMR 25.00 apply to all Distribution Companies subject to the jurisdiction of the Department of Public Utilities.

(2) Specific Definitions.

Basic Service shall mean the Generation, Transmission, and Distribution Services that shall be offered by a Distribution Company to customers within its service territory when, for any reason, a customer does not obtain Generation Service from a Supplier, including but not limited to when (1) a residential or non-residential customer chooses to buy Generation and Distribution Services from the Distribution Company; (2) a residential or non-residential customer does not actively choose a Supplier; (3) a residential customer has been denied Generation Service by other Suppliers for any reason, including for non-payment; or (4) a residential or non-residential customer's Supplier fails to provide Generation Service.

Basic Service Customer shall mean a user of Basic Service, as supplied by a Distribution Company.

Bill shall mean a written statement from a Distribution Company to its customer setting forth the amount of electricity consumed or estimated to have been consumed, and charges for Generation, Transmission, Distribution, and any other charges approved by the Department for the billing period identified in the Distribution Company's tariff.

Low-income Tariff shall mean a tariff providing a discount for Transmission and Distribution Services offered by a Distribution Company to Low-income Customers.

Universal Service shall mean the provision of electricity, offered through a Distribution Company to qualifying Low-income Customers, at a discount rate for Transmission and Distribution Service, and for Stranded Cost recovery.

(3) Universal Service.

(a) Each Distribution Company shall file a Low-income Tariff containing rates that differentiate, at a minimum, costs related to Generation, Transmission, Distribution, and Ancillary Services. Such tariff shall be designed to provide a level of protection for Low-income Customers that is equivalent to that provided under each Electric Company's Low-income Tariff as it existed on the effective date of these regulations.

(b) When filing a general rate case, each Distribution Company shall (1) calculate the projected total revenue deficiency resulting from the Low-income Tariff, (2) show the allocation of that deficiency among rate classes, (3) show the impact of the proposed Low-income Tariff on the company's other ratepayers by providing class-specific bill impact analyses, and (4) recover the low-income deficiency allocated to each class via the General Access Charge.

(c) Low-income Customers shall be eligible for the Low-income Tariff whether they choose Basic Service or Generation Service from another Supplier.

(d) Each Distribution Company will be responsible for determining eligibility for its Low-income discount and administering a Low-income Tariff within its service territory.

(e) Universal Service also shall incorporate billing and termination protections for all residential customers receiving Basic Service, as set forth at 220 CMR 25.00.

(f) Low-income Customers whose Generation Service has been terminated by another Supplier shall immediately be placed on Basic Service.

(4) <u>Basic Service</u>.

(a) Each Distribution Company shall be required to connect all customers within its service territory to its distribution system.

(b) <u>Requirement to Offer Basic Service</u>.

(1) Each Distribution Company shall have the obligation to provide Basic Service to customers in its service territory.

(2) For the first five years after the effective date of these rules, each Distribution Company with an affiliated Supplier shall procure Generation for Basic Service from the Power Exchange. The price for the Generation component of Basic Service shall be consistent with that charged by the Power Exchange.

ALTERNATIVELY

(2) Each Distribution Company with an affiliated Supplier may provide Generation for Basic Service from any Supplier, including an affiliated Supplier. The terms and rates for such service are subject to Department review and approval and, at a minimum, are subject to Section 11.06(3).

(3) Each Distribution Company without an affiliated Supplier may provide Generation for Basic Service from any Supplier.

(4) Effective January 1, 1998, each Distribution Company shall notify all customers in its service territory of the options available to them to procure electric service.

(5) A customer may request Basic Service from a Distribution Company at any time subject to 220 CMR 11.05(9).

(6) Residential customer. Each Distribution Company shall be required to offer Basic Service to each residential customer (a) who chooses not to enter into a contract for Generation Service with a Supplier, (b) who has been denied service by a Supplier for any reason including for non-payment, or (c) whose Supplier fails to provide Generation Service.

(7) Non-residential customer. Each Distribution Company shall be required to offer Basic Service to each non-residential customer (a) who chooses not to enter into a contract for Generation Service with a Supplier, or (b) whose Supplier fails to provide Generation Service.

(c) A Distribution Company may recover bad debt expenses incurred as a result of customers' failure to pay. Recovery of such expenses shall be established in distribution rates approved by the Department in a general rate case.

(5) Termination Protections.

(a) Each residential customer receiving Basic Service shall be protected from termination of such service pursuant to the terms set forth in 220 CMR 25.03; 220 CMR 25.04; and 220 CMR 25.05.

(b) Each Distribution Company shall remain responsible for determining eligibility for termination protections pursuant to 220 CMR 25.00 and administering such protections for customers receiving Basic Service within its service territory.

(6) Billing.

(a) Each residential customer receiving Basic Service shall be billed by a Distribution Company in accordance with the Billing and Termination Procedures set forth at 220 CMR 25.00.

(b) Each customer shall receive one bill for all electric services, unless either the customer or the Supplier requests separate billing for Generation Service.

(c) Each Distribution Company shall remain a billing authority for purposes of 220 CMR 25.00.

(d) Any residential customer receiving Basic Service complaining of any matter relating to the proper application of approved rates and charges, or about compliance by a Distribution Company with Department regulations, may pursue such complaint in accordance with the terms set forth at 220 CMR 25.02(4).

(7) Requirements for Service.

(a) Residential Customers. Each residential customer shall remain connected to a Distribution Company's system and be eligible for Basic Service from the Distribution Company provided that the customer has:

(1) fully paid all past due bills rendered by the Distribution Company to the customer; or

(2) established a payment plan agreement with the Distribution Company for payment of any overdue bill that remains outstanding in the name of the customer.

(b) Non-residential Customers. Any non-residential customer shall remain connected to a Distribution Company's system and obtain Basic Service from the Distribution Company provided that the customer meets the requirements of 220 CMR 11.05(4)(b)(7) and provided that the customer has:

(1) fully paid all past due bills rendered by the Distribution Company to the customer; or

(2) established a payment plan agreement with the Distribution Company for payment of any overdue bill that remains outstanding in the name of the customer.

(8) Security Deposit and Late Payment Charges. A Distribution Company may require a security deposit and impose late payment charges, as appropriate, from a non-residential customer in accordance with the terms set forth at 220 CMR 26.00.

(9) Right to Change Suppliers.

(a) Residential Customers.

(1) Residential customers shall be allowed to change Suppliers at any time, subject to any contractual obligations to a Supplier.

(2) If a residential customer has been denied Generation Service by a Supplier, or if the Supplier has failed to provide Generation Service, the Distribution Company in whose service territory the customer is located must immediately provide Basic Service.

(3) If a Supplier has failed to, or ceases to, provide Generation Service to a customer with which it has contracted, the Supplier must notify the Distribution Company of such failure or cessation. The Distribution Company must then notify the residential customer that the Supplier has failed to provide Generation Service. The customer shall

receive Basic Service until such time as the customer chooses a new Supplier, and the new Supplier provides such notice to the Distribution Company.

(b) Non-residential customers. Non-residential customers shall be allowed to change Suppliers at any time, subject to any contractual obligations to a Supplier. If a Supplier has failed to, or ceases to, provide Generation Service to a customer with which it has contracted, the Supplier must notify the Distribution Company of such failure or cessation. The Distribution Company must then notify the non-residential customer that the Supplier has failed to provide Generation Service. The customer shall receive Basic Service until such time as the customer chooses a new Supplier, and the new Supplier provides such notice to the Distribution Company.

11.06: Corporate Rules of Conduct

(1) Purpose and Scope.

(a) Purpose. This Section sets forth the Rules of Conduct by which Distribution Companies and their affiliates must conduct business in Massachusetts.

(b) Scope. This Section applies to all Distribution Companies and their affiliated Suppliers. These Rules of Conduct are not intended to supersede existing applicable law and regulations.

(2) Specific Definition.

Antitrust Laws consist of federal and state statutes, including the Sherman Act, 15 U.S.C. §§ 1-7, the Clayton Act, 15 U.S.C. §§ 12-27, and the Massachusetts Antitrust Act, G.L. c. 93, §§ 1-14A, which were designed to protect trade and commerce from unlawful restraints, undue price discrimination, certain forms of concerted behavior such as price fixing, and monopolization.

(3) Rules of Conduct.

(a) A Supplier offering power to an affiliated Distribution Company for the distribution system's stability or reserve needs shall make the power available to the market on the same conditions.

(b) A Distribution Company shall supply services and apply tariffs to affiliates and to non-affiliates in the same manner, and shall uniformly enforce its tariff provisions.

(c) A Distribution Company shall not give an affiliate preference over a non-affiliate in processing a request by a customer for service.

(d) A Distribution Company shall simultaneously make available to the market any and all information it provides to an affiliated Supplier.

(e) To the extent that a Distribution Company provides to an affiliated Supplier information not readily available or generally known to any other Supplier, the Distribution Company shall provide such information to all non-affiliated Suppliers operating in its service territory. The Distribution Company shall make provisions for those customers who indicate that their customer-specific information is to remain confidential.

(f) Employees of a Distribution Company who have responsibility for operation of the distribution system, such as receiving requests for power, purchasing power, or scheduling delivery, shall not be shared with an affiliated Supplier, and their offices shall be physically separated from the offices of the affiliated Supplier. Any shared facilities shall be fully and transparently allocated between the two entities. Separate books of account and records shall be maintained for each such affiliate.

(g) A Distribution Company shall not condition the provision of any distribution services on the purchase of power from an affiliate.

(h) A Distribution Company shall establish and file with the Department a dispute resolution procedure to address complaints alleging violations of these rules.

(i) Nothing in these rules shall be construed to modify, impair, or supersede the Antitrust Laws.

11.07: Supplier Registration Requirements

(1) Purpose and Scope.

(a) Purpose. The purpose of this Section is to establish the public information that shall be filed by any entity seeking to sell electricity to retail customers or seeking to aggregate customers for the purpose of selling electricity at retail.

(b) Scope. This Section applies to all Suppliers seeking to do business in the Commonwealth of Massachusetts.

(2) Registration Requirements. At least ten days prior to initiating Generation Service, each Supplier shall file with the Department's Secretary a notarized document that includes the information identified below. An updated registration shall be filed with the Department in response to any material change to the information on file.

(a) Legal name;
(b) Business address;
(c) If corporation or association, (i) the name of the state where organized, (ii) the date of organization, (iii) a copy of the Articles of Incorporation or Association, and (iv) the name, address and title of each officer and director;
(d) Name, title, and telephone number of customer service contact person;
(e) Name, title, and telephone number of regulatory contact person;
(f) Brief description of the nature of business being conducted;
(g) Evidence of financial soundness such as surety bonds, a recent financial statement or other mechanism, as determined by the Department.

(3) Each Supplier wishing to switch a customer from another Supplier to its own Generation Service shall obtain that customer's written (or other verifiable) authorization before providing service and shall preserve such authorization in its files for one year.

11.08: Renewables

(1) Purpose and Scope.

(a) Purpose. The purpose of these regulations is to establish the terms and conditions by which the Department goals of customer choice, environmental protection, and fuel diversity are advanced through the availability of renewable energy to customers in a restructured electric industry.

(b) Scope. This Section applies to all Distribution Companies.

(2) Specific Definitions.

Interconnection Standards shall mean any rules that govern the connection of Suppliers to a distribution system.

Renewable Energy Resources shall mean those resources whose common characteristic is that they are non-depletable or are naturally replenishable but flow-limited.

Renewables Fund shall mean monies collected from customers of a Distribution Company via the General Access Charge that are available to be distributed to Renewable Energy Resource providers to offset some or all of the difference between the price of power from emerging renewable energy technologies and the price that customers are willing to pay for power from Renewable Energy Resources.

(3) Funding of Renewables. A charge shall be established to support the Renewables Fund. This charge shall be part of the General Access Charge collected by the Distribution Company. Monies from the Renewables Fund shall be distributed to Renewable Energy Resource providers in a manner to be determined by the Department.

(4) Power Buy-Back. A customer of a Distribution Company with a Renewable Energy Resource of 30 kilowatts or less in size may run the meter backwards and receive from the Distribution Company the market price for generation in effect at the time of payment [or the customer's total retail price per kilowatthour (See Section V.C of the Explanatory Statement)] for the positive net difference between kilowatthours delivered and consumed. The customer will not be required to pay any charge for the kilowatthours sold back to the Distribution Company pursuant to this Section.

(5) Interconnection Standards. Non-discriminatory Interconnection Standards and rules shall be established by each Distribution Company so that Renewable Energy Resource providers have access to its distribution system and have the ability to sell power into the Power Exchange, directly to customers, or to Suppliers.

(6) Availability of Information. Each Distribution Company shall make any and all information that it has obtained on renewable energy technology available to its customers.

11.09: Energy Efficiency

(1) Purpose and Scope.

(a) Purpose. This Section establishes the rules by which each Distribution Company shall provide Energy Efficiency services to its customers.

(b) Scope. This Section applies to all Distribution Companies.

(2) Specific Definitions.

Demand-side Management ("DSM") shall mean any technology, measure, or action designed to decrease the kilowatt or kilowatthour consumption, or to alter the time pattern of that consumption, by consumers of electricity.

Energy Efficiency shall mean the application of the least amount of energy required to produce a desired output.

Energy Efficiency Plan shall mean a proposal by a Distribution Company to provide DSM and to participate in other Energy Efficiency initiatives.

Market-Driven Energy Efficiency shall mean Energy Efficiency efforts designed to take advantage of opportunities for more efficient use of energy presented by the market at the time when it is most practical and inexpensive to do so, such as during new construction, renovation, equipment replacement, or at the time of purchase of new equipment.

Market Transformation Initiatives shall mean strategic efforts to offset market failures and to induce lasting structural or behavioral changes that result in increases in the adoption or penetration of energy efficient technologies or practices.

Weatherization Assistance Program ("WAP") Agency shall mean an entity charged with the implementation of energy efficiency direct installation programs that provide weatherization services and other measures to reduce energy use by Low-income Customers.

(3) Filing Requirements. Each Distribution Company shall file a proposed Energy Efficiency Plan with the Department at the time it files its first conservation charge filing subsequent to the issuance of these rules. Each Energy Efficiency Plan shall extend for a period of five years.

(4) Department Review. The Department shall review the Energy Efficiency Plan at the time it is filed, and then again after three years, to determine the extent to which the Energy Efficiency Plan continues to reduce market barriers to Energy Efficiency, and to determine the level of cost recovery appropriate to fund the Energy Efficiency Plan. The Department shall approve such Energy Efficiency Plan, or order such changes to the Plan as necessary to achieve the purpose of this Section.

(5) Content of Energy Efficiency Plans. Each Distribution Company's Energy Efficiency Plan shall include:

(a) An educational component that seeks to ensure that customers have adequate information about Energy Efficiency for informed decisionmaking;

(b) A proposal for support of regional or national Energy Efficiency Market Transformation Initiatives to the extent that they can provide benefits to the company's customers;

(c) A description of the evolution of the company's DSM programs to market-driven efforts during the years covered by the plan;

(d) A proposal for the company to coordinate delivery of Energy Efficiency services to Low-income Customers with the local WAP agencies; and

(e) A funding proposal for the delivery of Energy Efficiency services to Low-income Customers that ensures that the company is neutral as to the provision of Energy Efficiency or Generation Service to Low-income Customers.

(6) Funding of Energy Efficiency Services. Energy Efficiency services provided by a Distribution Company to customers other than the Low-income Customers shall be funded through the General Access Charge.

(7) Public Availability of Information. Each Distribution Company shall make any and all information that it has obtained through ratepayer funds regarding energy efficiency technology, measures, or actions available to the public. Each Distribution Company shall make provisions for those customers who indicate that their customer-specific energy efficiency information is to remain confidential.

11.10: Exceptions

Upon motion, the Department may grant, where appropriate, an exception to any provision of Section 11.00. The Department may act upon its own motion in granting such exception.

REGULATORY AUTHORITY

220 CMR 11.00; M.G.L. c. 164 §§ 69I, 76, 94